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SOLAR PHOTOVOLTAIC AND LIQUID NATURAL GAS OPPORTUNITIES FOR COMMAND NAVAL REGION HAWAII

December 2014

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SOLAR PHOTOVOLTAIC AND LIQUID NATURAL GAS OPPORTUNITIES FOR COMMAND NAVAL REGION HAWAII

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Submitted in partial fulfillment of the requirements for the degree of

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ABSTRACT

This thesis examines the costs and benefits of two onsite energy opportunities for Command Naval Region Hawaii (CNRH) and the surrounding region. The project analyzes a proposed 50-MW solar photovoltaic (PV) system on West Loch Peninsula in Pearl Harbor, Hawaii, and the economic impacts of a proposed liquid natural gas (LNG)-import terminal on Waipu Peninsula in Pearl Harbor, using net present value (NPV) and cost benefit analysis. CNRH is considering collaboration with Hawaiian Electric Companies to pursue the proposed PV plant and the LNG terminal in order to meet Hawaiian Clean Energy Initiative requirements for producing 40% renewable energy by 2030. The goal of this project is to calculate the economic impacts an LNG-import terminal might have on solar PV and potential indirect impacts of pursuing both projects.

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LIST OF ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
AFR	Annual Financial Report
APZ	Accident Potential Zone
ATB	Articulated Tug Barge
BAH	Basic Allowance Housing
BATNA	Best Alternative To Negotiated Agreement
BESS	Battery Energy Storage System
CBA	Cost Benefit Analysis
CNG	Containerized Natural Gas
CNRH	Command Naval Region Hawaii
c-Si	Monocrystalline Silicon
DBEDT	Department of Business Economic D Tourism
dc	Direct Current
Disc	Discounted
DOE	Department of Energy
EIA	U.S. Energy Information Administration
EPRI	Electric Power Research Institute
EUROELECTRIC	European Electric
FACTS	Fesharaki Associates Consulting & Technical Services, Inc.
FERC	Federal Energy Regulatory Commission
FGE	FACTS Global Energy
FSRU	Floating Storage Regasification Unity
GoM	Gulf of Mexico
GWh	Giga Watt Hour
HAR	Hawaii Administrative Rules
HRS	Hawaii Revised Statues
HCEI	Hawaiian Clean Energy Initiative
HECO	Hawaiian Electric Companies

HELCO	Hawaii Electric Light Company
HEI	Hawaiian Electric Industries Inc.
HI	Hawaii
HRS	Hawaii Revised Statutes
HSIS	Hawaii Solar Integration Study
IPP	Independent Power Producers
JBPHH	Joint Base Pearl Harbor Hickam
KIUC	Kauai Island Utility Cooperative
Kw	Kilo Watt
kWh	Kilo Watt Hour
kWh-yr	Kilo Watt Hour- Year
LA	Louisiana
LNG	Liquid Natural Gas
LCOE	Levelized Cost of Energy
LS	Low Sulfur
LSD	Low Sulfur Diesel
LSFO	Low Sulfur Fuel Oil
mmBtu	Million British Thermal Units
mmtpa	Million Tons Per Annum
MW	Mega Watt
NAFAC	Naval Facilities Engineering Command
NEPA	National Environmental Policy Act
NPV	Net Present Value
NS	Naval Station
O&M	Operational And Maintenance
OMB	Office of Management and Budget
OR	Oregon
PBN	Pacific Business News
PPA	Power Purchase Agreement
PUC	Public Utilities Commission

PV	Photovoltaic
Pwr	Power
RE	Renewable Energy
Re-gas	Regasification
RFP	Request For Proposal
RMI	Rocky Mountain Institute
ROI	Return On Investment
SNG	Synthetic Natural Gas
STL	Single Tending Line
STS	Ship-To-Ship
TX	Texas
W	Watt
WA	Washington
WACC	Weighted Average Cost of Capital
U.S.	United States
USWC	United States West Coast
S&P	Standard and Poors
ZOPA	Zone of Possible Agreement

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EXECUTIVE SUMMARY

Hawaiian Electric Companies (HECO) has overstated projected reductions in utility rates that may be realized by transitioning to liquid natural gas (LNG). HECO has communicated to Command Naval Region Hawaii (CNRH) that it expects utility costs to drop by 20–30% after building an LNG-import terminal (CNRH, 2013). Such a reduction is unlikely, because even a 50% reduction in fuel cost (the maximum savings projected by FACTS Global Energy and Galway reports) would result in only a 21% reduction in HECO’s 2013 total operating expense. This research estimates a 10–21% reduction in the utility rate as the maximum possible while maintaining the same operating margins.

The average annual rate to produce electricity with solar photovoltaic (PV) technology is projected to be $0.088/kWh. The average annual rate to deliver LNG to Hawaii is calculated at $0.10–$0.18/kWh. However, these figures are not directly translatable into utility rates. The solar PV rate does not consider grid tie-in costs, upgrades to advanced smart-grid technology, or the utility-scale storage that would be required to accommodate fluctuations in current under dynamic weather conditions. The LNG cost ignores the expense of transporting fuel from an import location to the power plant, the costs of operating a power plant, modernization and replacement of aging generators, and other ancillary expenses. While replacing LS diesel with LNG will almost certainly realize savings, further research is required to determine if LNG will reduce utility rates more than renewable energy.

BENEFITS FOR CNRH AND HECO

Building an LNG-import terminal in Pearl Harbor would be a mutually beneficial project for CNRH and HECO. CNRH would benefit by $32.2 million per year and HECO by $170–$460 million on average per year, based on projected net present value (NPV). The benefits of building an LNG-import terminal are much greater than the cost of either party’s alternative.

HECO's best alternative for a LNG site would be $50 million more expensive than locating the project at Pearl Harbor. For its part, CNRH will likely save $32.2 million annually in utility costs if an LNG terminal is constructed at Pearl Harbor.

ECONOMIC ANALYSIS OF LEASE AGREEMENT

The "zone of possible agreement" (ZOPA) theory suggests the most likely lease agreement would be reached at the midpoint between acceptable terms. In this case, the midpoint between HECO and CNRH would be $8.9 million per year.

Ultimatum theory suggests that when both parties stand to gain from a zero-sum transaction, the party with the lessor terms will not agree without a payout of 20% or more (Thaler and Mullainathan, 2008). This perspective places the lease rate at no less than 20% of HECO's economic benefit of $170 million per year, or $34 million per year.

THE SOLAR PV ALTERNATIVE

The solar-PV project is very attractive because of the $280–$800 million NPV for a 50-MW system at West Loch. However, the NPV does not include grid tie-in costs, smart-grid upgrades, or electrical-storage costs incurred to address significant fluctuations in electrical current. This study found that CNRH could invest a maximum of $280–$800 million in the excluded costs and still enjoy a positive NPV. The projected cost savings are largely attributed to whether electricity from the utility company can be displaced by the renewable energy generated or the renewable energy must be sold back to the utility company. The latter scenario would result in buying electricity for $0.28 per kWh and selling electricity for $0.19/kWh. The first scenario, CNRH using the energy produced, would reduce the quantity of electricity consumed at $0.28/kWh in essence saving $0.09 for every kWh used.

Building an LNG terminal will reduce the reimbursement rate which the utility company reimburses renewable energy. A 30% reduction in the utility reimbursement rate will result in a $200 million NPV loss for a 50-MW solar-PV system over 30 years. The renewable-energy reimbursement rate is determined by HECO's "avoided energy costs" submitted by HECO and approved by the Public Utility Commission. This means

the yearly cash flow paid by the utility company for solar-PV energy could be 30% less if an LNG-import terminal is installed. The only way to avoid drastic reductions in the renewable energy reimbursement rate is to enter into a long-term contract with HECO.

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I. INTRODUCTION

This thesis is an economic analysis of proposed solar photovoltaic (PV) and liquid natural gas (LNG) opportunities for Command Naval Region Hawaii (CNRH). The opportunities have arisen from Hawaii's abnormally high cost of energy and the Navy's interest in reducing carbon emissions while realizing cost savings. This report is an initial investigation into two projects that are potentially worth tens of millions of dollars to the CNRH and hundreds of millions of dollars to Hawaiian Electric Companies. To achieve carbon-emission and cost reductions, CNRH must pursue strategies that are consistent with Department of Defense and Hawaiian policy while meeting the highest standards of today's best engineering practices. While this report touches on public policy and engineering standards, it does not purport to be an authoritative source on either. The tools and calculations in this report may be altered and updated as Hawaiian policy and technical standards change.

A. BACKGROUND

CNRH is considering two opportunities to reduce energy costs. The first is the installation of approximately 50 MW of ground-mounted solar-PV panels on the West Loch Peninsula, on Pearl Harbor Naval Base. The second proposed project is a land lease to an unidentified private entity that would install an LNG-import terminal on Middle Loch Peninsula, also on Pearl Harbor Naval Base. A large quantity of the imported LNG would be piped to Hawaii Electric Company (HECO's) power facilities and used to replace diesel in thermal power generators. Both the solar-PV plant and the LNG-import terminal are projected to reduce CNRH's extremely high energy costs.

1. Costs

Hawaiian energy is expensive for multiple reasons, according to Jay M. Ignacio, president of Hawaii Electric Light Company (HELCO), a subsidiary of Hawaiian Electric Industries (HEI). The first is that the islands lack economy of scale, due to a small customer base and low customer density (HELCO, 2014). Utility companies in the

continental United States typically benefit from more customers and higher customer densities, which reduces costs overall (HELCO, 2014).

Second is Hawaii's geographical isolation. Considerable investment has been made in grid-infrastructure security, with many areas left for improvement (HELCO, 2014) Grid infrastructure security refers to factors that ensure the provision of stable electricity at all times.

Third, an additional high-tech distribution infrastructure is required for "variable generation" (renewable-energy) power producers to prevent harmful effects from large fluctuations in current and frequency (HELCO, 2014). In 2013, renewable energy constituted approximately 18% of the total energy production in Hawaii and this share is projected to grow (DBET, 2014). HELCO quotes a EURELECTRIC report that states, "Treatment of islands is not straightforward. Island [utility] markets are different and therefore require a different approach that is both reasonable and proportionate" (EURELECTRIC, 2012).

Two factors contribute to HECO's high fixed costs. First, owing to its isolation, Hawaii is unable to purchase power from neighboring utility companies that feed into a connected grid. Second, the large penetration of variable generation raises costs (HELCO, 2014). HECO is required to maintain spinning reserves higher resulting from higher penetration or renewable energy than its counterparts, which increases costs. HECO facilities therefore have an average fossil-fuel utilization rate of ~25% according to FACTS Global Energy (FGE), which did not find fault in the operational management of HECO's fossil-fuel plants (FGE, 2012).

HECO's power generation is largely dependent on oil, and thus vulnerable to oil-price volatility (HELCO, 2014). In 2012, 71% of Hawaiian power generation was based on oil, and 15% on coal (DBEDT, 2014). In addition, because Hawaii's renewable-energy compensation plans are incentivized from unused oil, renewable-energy compensations are also subject to oil-market volatility (HELCO, 2014).

As a result, the price of electricity in Hawaii is three times higher than the national average (DBEDT, 2014). In addition to the burden of high electricity rates,

HECO is also struggling in modernizing its infrastructure to meet pollution standards, according to the State of Hawaii Public Utility Commission (PUC, 2013). In 2012, Hawaii was 71% dependent on oil for power production, compared to 1% for the United States (DBEDT, 2014). In the same year, the continental United States was 37% dependent on coal, which is the least environmentally friendly fuel for power generation, and 30% dependent on natural gas (DBEDT, 2014), as shown in Figure 1.

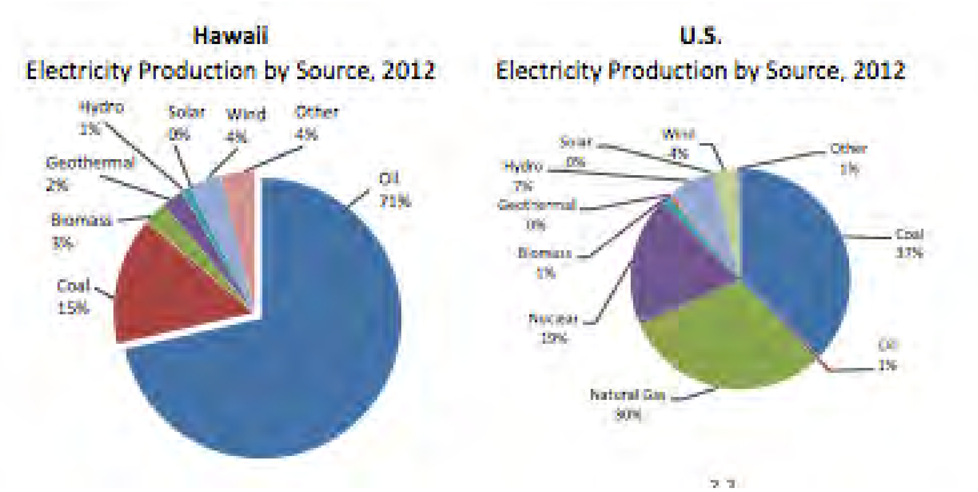

Figure 1. Electricity Production by Source, 2012 (DBEDT, 2014)

2. Public Policy

The PUC has become increasingly concerned over HECO's business operations and has used strong language to criticize the growing divide between desired PUC initiatives and those that HECO currently pursues. One example is found in a 2013 PUC document stating that "ratepayers at each of the HECO Companies are growing increasingly frustrated by high electric rates and poor customer service" (PUC, 2013b). The PUC noted that Maui Electric (a subsidiary of HEI) had been held financially accountable for inefficient performance—the PUC ordered a reduction in base electricity revenues of $7.7 million from current levels and a refund of more than $8 million to rate payers (PUC, 2013b). Furthermore, Maui Electric's authorized profit level was reduced (PUC, 2013b).

While the PUC and HECO have expressed a desire to work together to improve customer service and reduce electricity rates for “customers” (HECO) and “ratepayers” (PUC), the PUC has essentially taken a hardline stance toward HECO. This dynamic is extremely important to understand in evaluating the PUC’s willingness to approve an LNG-import terminal.

HECO is characterized as a monopoly and is therefore tightly regulated by the PUC. Credit-rating agencies, such as Standard and Poors (S&P), view the relationship between the utility and the PUC as a significant factor in the utility’s credit rating (NPR, 2012). S&P gave Hawaiian Electric Industries Inc. a BBB- rating in February 2014, which is the lowest investment-grade credit rating (Hawaiian Electric Industries Inc, 2014), citing “strong” business risk and a “significant” financial-risk profile (Hawaiian Electric Industries Inc., 2014). The implication is that HECO has to pay high interest rates for money, a problem when contemplating a large investment such as an LNG-import terminal; thus HECO will likely rely on a third party consortium to obtain financing for the proposed project (CNRH, 2014).

There is a significant ideological divergence between HECO’s pursuit of LNG and the PUC’s preference for renewable energy. The PUC wrote in its guidance to HECO,

> The costs of fuel and purchased power constitute the largest components in today’s high bills for electricity customers and represent major strategic opportunity for lowering electric rates…. Therefore, to further stabilize and lower the costs of generation, the HECO Companies should expeditiously:
>
> - Seek high penetration of lower-cost, new utility-scale renewable resources
> - Modernize the generation system to achieve a future with high penetrations of renewable resources
> - Exhaust all opportunities to achieve operational efficiencies in existing power plants
> - Pursue opportunities to lower fuel costs in existing power plants
>
> In carrying out these goals, the Commission puts forward the following guidelines for the review of future generation-related project in each of these areas. Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources… New generation resources should lower system costs and maximize use of cost-effective renewable resources” (PUC, 2013).

These guidelines emphasize that the PUC wants HECO to invest in renewable resources (PUC, 2014) (or as HECO puts it, variable generation [HELCO, 2014]). The PUC also wants HECO to modernize current plants and find new ways to lower fuel costs. While the latter could involve the use of LNG, the PUC's failure to mention the proposed $100+ million import terminal among its priorities is significant.

Increasing the use of LNG is not entirely dependent upon the construction of an import terminal. Hawaii Gas is already shipping containerized vessels to Oahu (EIA, 2014), and HECO is pursuing containerized LNG vessels, pending approval from the PUC (Shimogawa, 2014b). An article in *Pacific-Based News* states that

> Hawaii Electric Co. has selected a finalist for a project to supply and deliver to the state's largest electric utility hundreds of tons of liquefied natural gas to be used as a replacement fuel for power generation across Hawaii, the incoming head of the Honolulu-based company told PBN Tuesday (Shimogawa, 2014b).

The PUC report cited docket No. 2013–0381 as stating that

> …the average levelized price of the utility-scale solar PV projects included in the Application is 15.576 cents per kWh (calculated without state tax credits), which is significantly lower than HECO's avoided energy cost of electrical generation 22.697 cents per kWh in November 2013 (PUC, 2013).

The PUC cites HECO's records in finding that it is 30% cheaper to produce power via solar PV than the "avoided energy costs," which is HECO's cost to produce energy. However, the PUC did not consider additional costs. Hawaii Administrative Rule 6–74 defines "avoided energy costs" as including the cost of fuel, electrical generation and operation, and maintenance (Department of Budget and Finance, 1998). Additionally, avoided energy costs can include fuel inventory costs, working-cash costs, and line-loss costs, which are considered when presented in a specific proposal from a qualifying facility (Department of Budget and Finance, 1998). What is not considered in avoided energy costs is the cost of adding infrastructure upgrades such as smart-grid technology or utility-scale electrical storage to the grid to accommodate renewable energy (e.g., solar, wind), which will be required when renewable penetration exceeds 20% (HSIS, 2012). Therefore, the PUC reference to 15.576 cents per kWh is technically correct in

terms of the definition of avoided energy costs, but it is improperly used because higher penetrations of renewable energy are accompanied by expensive infrastructure upgrades (PUC, 2014). This problem will continue as renewable-energy distribution grows from 18% in 2013 to exceed 20%. (PUC, 2014) (DBET, 2014) (HSIS, 2012).

A study conducted by FACTS Global Energy, funded by the Hawaii Natural Energy Institute, an affiliate of the University of Hawaii, finds that,

> Some people worry that LNG will be so cheap that it will challenge renewables. This is a strange kind of logic, since it in effect is an argument that the best thing for Hawaii renewables would be if the customers all paid the highest energy prices possible. If that is to be State policy, then LNG is a bad idea. Our analysis here assumes that State policy is to lower prices within the HCEI framework, not keep them high. (FGE, 2012)

Before an LNG-import terminal is further explored, understanding PUC priorities is essential. These include aggressive pursuit of lower costs, new utility-scale renewable resources, and reduced fuel costs in existing power plants (PUC, 2014). It remains unclear whether lowering these fuel costs by means of an LNG-import terminal is consistent with the PUC's intended framework.

3. Solar PV

The high cost of electricity presents many opportunities for solar PV in Hawaii, as well as challenges. Installation of solar PV has rapidly grown, due to a significant cost reduction in panels, increased federal and state tax incentives, more stringent emissions targets, and a rise in available financing for renewable energy projects (Rocky Mountain Institute, 2014) (Medelsohn and Harper, 2012) (Medelsohn and Kreycik, 2012) (Strand and Seligman, 2013). The Rocky Mountain Institute (RMI) found in 2013 that solar PV in Hawaii was more cost effective than local utility rates (RMI, 2014). In 2013, renewable energy constituted approximately 18% of total energy production in Hawaii (DBET, 2014). Solar PV contributed 4.3% of the renewable total, but it is the fastest-growing sector in the Hawaiian renewable-energy market (DBET, 2014). Figure 2 shows solar as a percentage of total renewable-energy generation in Hawaii. Figure 3 shows the number of PV systems installed in Hawaii as of 2013. Figure 4 shows cumulative solar-

PV generation in MW per year. Figure 5 lists completed utility-scale solar projects in the State of Hawaii.

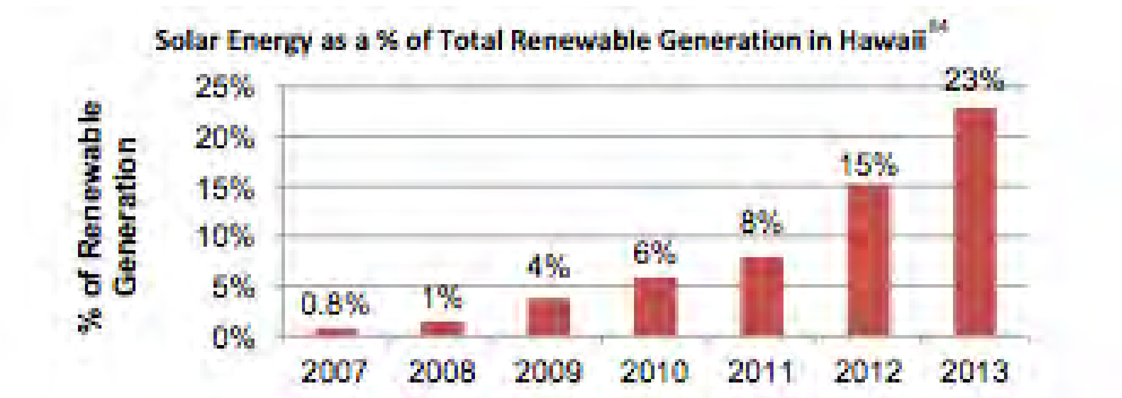

Figure 2. Solar Energy as a Percentage of Total Renewable Generation in Hawaii (DBET, 2014)

	Number of PV systems	Capacity (MW)
HECO	29,558	221
HELCO	5,355	41
MECO	5,255	38
KIUC	1,875	12.3
TOTAL	**40,717**	**312.3**

Figure 3. Quantity and Capacity of PV Systems (DBET, 2014)

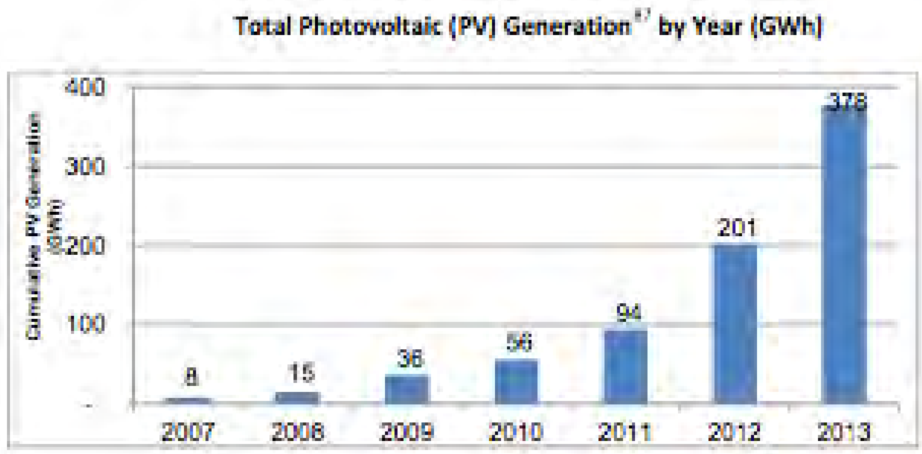

Figure 4. Total Photovoltaic (PV) Generation by Year (GWh) (DBET, 2014)

Existing Utility Scale Solar Projects

Project Name	Year Installed	Island	Developer	Capacity
La Ola Solar Farm	2006	Lanai	Castle & Cooke	1.1 MW
Kapolei Sustainable Energy Park	2011	Oahu	Forest City, Hoku	1.18 MW
Kapaa Solar Project	2011	Kauai	Kapaa Solar, KIUC	1.21 MW
Port Allen Solar Facility	2012	Kauai	A&B, McBryde, KIUC	6 MW
Kalaeloa Renewable Energy Park	2013	Oahu	Hanwha SolarEnergy, Swinerton, Scatec, Hunt Dev	5 MW
Kalaeloa Solar Power II	2013	Oahu	SunPower, Dept. of Hawaiian Homelands	5 MW
MP2 Solar Project	2013	Kauai	REC Solar, KIUC	300 kW
Pearl Harbor Peninsula	2013	Oahu	Forest City, NAVFAC, HECO, HOKU	1.23 MW

Figure 5. Existing Utility Scale Solar Projects (DBET, 2014)

According to HECO, the cumulative PV power generation capability in 2013 was 221 MW, generated from 29,558 different systems (DBEDT, 2014). HECO believes that the growing employment of solar PV, with its variable-generating nature, “present[s] a severe risk to the security of the system” (HELCO, 2014). Fluctuations in demand for electricity were met with fast-start diesels and simple-cycle combustion turbine generators in 2012 (HELCO, 2014), which, being able to operate quickly, were used to mitigate fluctuations in wind and PV generation (HELCO, 2014). As the supply of renewable energies increases, the grid will become more vulnerable if corrective actions are not taken.

The Rocky Mountain Institute wrote in 2014 that solar-PV-plus-battery and diesel generators in commercial systems were either as cost effective or below parity with the Hawaiian grid (RMI, 2014). In the same report, RMI projected that by the end of 2014, solar-plus-battery will be on par with the grid for commercial applications, which could lead to mass defection from dependence on the utility (RMI, 2014). The study noted that as more people defect from the grid, the utility's fixed costs will be distributed among fewer ratepayers, thus hastening the "death spiral" coined by Liam Denning in a December 2013 *Wall Street Journal* article (RMI, 2014) (McMahon, 2014).

4. Liquid Natural Gas

HECO seeks to curb the high costs of energy production by using liquid natural gas (LNG) instead of costly low-sulfur (LS) fuel oil or LS diesel. A 2012 study by FGE states that "LNG could provide fuel savings in the Oahu power sector of 30–50% or more compared to oil" (FGE, 2012). The study calculated that savings in 2020 would range from 31–47% contingent on fuel costs delivered to Oahu, if LNG demand is greater than 0.5 mtpa, and if U.S.-built Jones Act-compliant carriers from the U.S. West Coast could deliver the LNG to an onshore facility (FGE, 2012). Table 1 shows the projected percentage decrease in costs from delivering LNG to Oahu as compared to LS diesel.

Table 1. Savings in Delivered Energy Cost, LNG vs Low-Sulfur Diesel, 2012 U.S.$/mmBtu (from FGE, 2012)

	2015	2020	2025	2030
Alaska	na	na	8%	8%
Australia	-8%	3%	3%	4%
Canada	na	14%	15%	16%
US Gulf Coast	33%	35%	32%	31%
US West Coast	na	47%	44%	43%

** Because of new EPA policies, LS diesel is expected to be the main utility fuel in Hawaii before 2020. At present, on Oahu LS diesel and LS fuel oil are almost identical in cost per mmBtu.*

It should be noted that these projected savings are contingent upon LNG's being sourced from the continental United States, with Jones-Act compliant or -exempt ships available to transport the fuel (FGE, 2012). Savings are less than half if the LNG is sourced from Canada.

LNG is less expensive than LS diesel and more environmentally friendly than oil or coal (EPA, 2014). Table 2 illustrates that LNG combustion produces less carbon dioxide, sulfur dioxide, and nitrogen oxide than either oil or coal.

Table 2. By Products of Fuel Combustion (from EPA, 2000)

	Oil	Coal	LNG
Carbon Dioxide	1672	2249	1135
Sulfur Dioxide	12	13	0.1
Nitrogen Oxide	4	6	1.7

Units are in lbs/ MWh
Figures are from U.S. EPA, eGrid 2000
All Units are for US power plants.

Experts disagree as to whether the findings in Table 2 translate directly to a potential national reduction in carbon emissions. Research conducted by the University of California, Irvine; Stanford University; and the nonprofit organization Near Zero have released findings indicating that increased LNG use would have an insignificant benefit on the environment, as compared to coal (Nunez, 2014). The report found "between 2013 and 2055 the use of natural gas could reduce cumulative emissions from the electricity sector by no more than 9 percent" (Nunez, 2014). Their research concluded that LNG is not a suitable bridge fuel from coal to renewable energy from an environmental perspective.

HECO commissioned the firm of Galway Energy Advisors LLC to study the commercial viability of importing LNG to Oahu. Completed in October 2012 (Galway, 2013), the Galway report stated that importing LNG would be economically beneficial, that Pearl Harbor would be the most economically viable location for an LNG terminal

(Galway, 2013), and that HECO could use the same diesel power-generation infrastructure, with minor upgrades (Galway, 2013).

5. Energy Storage

HECO announced in a May 2014 press release that it is pursuing investments in a storage technology that will accommodate 60–200 MW of energy for up to thirty minutes (*Wall Street Journal*, 2014). HECO's request for proposal (RFP No. 072114-01) observes that

> rapid growth in variable renewable energy penetration to the electrical grid has become a challenge to manage. The intermittent nature of wind and solar generation require that the existing thermal generation fleet since it needs to manage the volatility of the variable generation. Voltage and frequency regulation on the grid are expected to become increasingly challenging with progressively higher levels of variable renewable generation. (Wall Street Journal, 2014)

In September 2014, *Pacific Business News* reported that HECO was negotiating with three energy-storage developers after receiving 60 proposals (Shimogawa, 2014). "Colton Ching, vice president for energy delivery for HECO... [stated that] all three are proposing battery storage. We hope to sign contracts with all three that offer the best value for Oahu electric customers" (Shimogawa, 2014).

Energy storage could be extremely useful in protecting the grid from power fluctuations. Utility-scale energy storage could also be designed to back up critical infrastructure in the event of complete power loss.

6. Renewable Energy Reimbursement

The State of Hawaii has a net-metering initiative that allows customers to pay solely for electricity utilized minus the amount of energy the customer produced via renewable energy (Energy.gov, 2014). However, net metering is restricted to a less-than 100-kW capacity for individual systems in Oahu. Several pilot programs have been instituted by the HECO utilities, as mandated by the PUC, to allow larger systems to qualify for net metering that is "technically and economically reasonable and practicable" (Energy.gov, 2014). However, the pilot program's maximum capacity falls far short of

the 50-MW solar PV capacity that is proposed for Pearl Harbor Naval Base (Energy.gov, 2014) (CNRH, 2014).

Whether solar PV infrastructure is purchased by the Navy or an independent entity with whom the Navy negotiates a power-purchase agreement (PPA), the 50-MW system would be reimbursed by HECO at a rate of no less than the avoided energy costs. These costs range from 19 cents/kWh on peak demand to 15 cents/kWh in the off-peak, providing that the system is tied into the local utility grid (HECO, 2014a). An independent power producer (IPP) or the Navy could negotiate a rate exceeding the avoided energy costs if the agreement is signed no later than one year after the plant is brought online. The excerpts below outline the legal precedent for avoided energy costs, found in Docket No. 7310, Decision Order No. 24086, filed March 11, 2008.

> Our reading of [HAR chapter 6–74], the applicable state statute, and federal rules and regulations is that a utility and an independent power producer are not precluded from negotiating a contract that contains a front-end loaded energy rate and an environmental and security premium pricing structure. Both [Hawaii Revised Statutes ("HRS")] 269–27.2 and HAR 6–74-22 (a) (3) require only that rates from power purchases be not less than 100 per cent of the utility's avoided energy cost and not less than the minimum purchase rate. Moreover, HAR 6–74-15 (b) (1) provides that nothing in subchapter 3 of [HAR Chapter 6–74] "prohibit [s] an electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relation to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subchapter.
>
> Although a qualifying facility and a utility may negotiate a contract containing [a] front-end loaded energy rate and avoided external cost pricing structure, any such contract must receive the commission's approval if the utility is to recover any payments it makes under the contract from its ratepayers. In its review of such a contract, the commission must determine, among other things, whether the rate and pricing structure are just and reasonable and in the overall best interest of the general public. In making that determination, the appropriateness of a front-end loaded energy rate and pricing structure in the particular contract is a relevant consideration. (PUC, 2008)
>
> HAR 6–74-1 defines "minimum purchase rate" in terms of utility's avoided energy cost. In the case of a legally enforceable contract between a qualifying facility and the utility, the minimum purchase rate is the utility's avoided energy cost in effect on the date the contract becomes

> effective. Where there is no contract in excess of one year, the minimum purchase rate is the utility's avoided energy cost in effect on the date the qualifying facility delivers energy to the utility." (PUC, Footnote Nine, 2008)

The avoided energy costs (> 100kW). Schedule "Q" rates (< or = 100 kW) Q-rate (cents/kWh) on July 1, 2014 in Oahu. On-peak avoided energy cost was 19.701 (HECO, 2014a). The off-peak avoided energy cost was 15.143, and the Schedule Q for systems less than 100 kW was 17.33 (HECO, 2014a).

7. Legislation

The Hawaii Clean-Energy Initiative was passed in January 2008 to create a roadmap from oil to renewable-energy power generation (Braccio, Finch, and Frazier, 2012). "Hawaii Clean Energy Initiative set a goal of generating 70% of electricity from renewable sources by 2030; 40% from local generation and 30% from energy efficiency and conservation measures" (Megan Strand and Jake Seligaman, 2013). Residential, commercial, and utility-scale solar PV all play a part in reaching this goal.

The DOD has strict guidelines regulating the transition to renewable energy. The "National Defense Authorization Act of 2010: Section 2842 requires the DOD to produce or procure 25 percent of its total facility energy use from renewable sources, beginning in 2025" (Environmental and Energy Study Institute, 2011). Naval Base Pearl Harbor needs to procure 179,371 MWh per year by 2025 if energy consumption remains at FY 2013 levels (B. Law, email to author, October 24, 2014).

B. OBJECTIVE OF THIS STUDY

This study analyzes the best information available and presents decision makers with recommendations as to which proposed energy projects offer the greatest benefit to the DOD and United States taxpayer.

C. RESEARCH QUESTIONS

- For CNRH, what is the NPV of a 50-MW solar PV installation?

- What is the leased value of the land for an LNG-import terminal (~.55mmpta)?
- What is the difference in cost between using Pearl Harbor land and a floating LNG terminal?
- If an LNG-import terminal were built, what percentage could the CNRH expect to save on its utility bill?
- What impact would an LNG-import terminal have on independent renewable-energy power producers due to PUC-mandated avoided energy costs?

D. SCOPE OF STUDY

This study is limited to economic analysis of a 50-MW solar-PV project on the West Loch Peninsula and an LNG-import terminal, both on Pearl Harbor Naval Base, from the perspective of CNRH.

E. ORGANIZATION OF THIS STUDY

This thesis contains six chapters. Chapter I includes the background, objective, research questions, and scope of investigation. Chapter II presents a review of relevant documents. Chapter III describes the methodological approach, NPV, and years to break even for solar PV. Chapter IV analyzes findings, beginning with an introduction, basic assumptions, and data and sensitivity analyses and concluding with a note on the study's limitations. Chapter V provides an economic analysis of the LNG-import terminal. Chapter VI summarizes findings and gives recommendations.

II. LITERATURE REVIEW

A. "TRACKING THE SUN VII"

"Tracking the Sun" is a report funded by the Lawrence Berkeley National Laboratory and the U.S. Department of Energy to examine data on installed solar PV in the United States (Barbose, Weaver, and Darghouth, 2014). The study synthesizes data from approximately 300,000 individual residential solar, commercial, and utility-scale PV systems, which represents 80% of the installed solar capacity in the United States (Barbose et al., 2014). The intent of the study was to track the installed costs of solar PV before tax incentives. The report separates the costs among residential, commercial, and utility systems. This thesis concerns trends in utility-scale PVs only.

The report found that "capacity-weighted average installed prices fell by 40%, from $5.0/W for the 5 systems [utility-scale solar-PV projects] installed during the 2007–2009 period to $3.0/W for the 25 systems completed in 2013" (Barbose et al., 2014). However, there was negligible price reduction in the 25 utility-scale projects completed in 2013 when compared with utility projects completed in 2012 (Barbose et al., 2014). Possible explanations for this cost flattening include the use of increased premium efficiency modules and solar-PV unit-tracking capabilities (Barbose et al., 2014).

The report documented a significant decrease in the cost of crystalline silicon (c-Si) modules as compared to thin-film modules (Barbose et al., 2014). "Average installed prices [of crystalline silicon] fell by $3.4/W (52%) between the 2007–2009 period and 2013;" however, thin-film prices remained virtually the same during that period (Barbose et al., 2014).

Prices of the 25 utility-scale solar projects completed in America in 2013 varied considerably, ranging from $1.9/W to $4.9W, with most of the projects ranging from $2.6/W to $3.5/W (Barbose et al., 2014). The capacity-weighted average-installed-price for c-Si modules and tracking was $3.1/W and $3.0/W for fixed- tilt (Barbose et al., 2014). Thin-film systems cost less, at $2.7/W for fixed-tilt (Barbose et al., 2014).

The study found that larger systems did not reflect cost savings due to economies of scale (Barbose et al., 2014). Additionally, the costs for systems completed in 2012 and 2013 that were greater than 50 MW had a cost per Watt between a narrow range of \$2.6/W to \$3.2/W (Barbose et al., 2014).

B. HAWAII SOLAR INTEGRATION STUDY

The Hawaii Solar Integration Study was commissioned by HECO in response to the Hawaii Clean-Energy Initiative (HSIS, 2012). A research team analyzed numerous scenarios with various amounts of solar and wind generation (HSIS, 2012).

The study found that the Oahu grid could accommodate up to 20% renewable energy before point grid security began to be compromised (HSIS, 2012). The study stated that integrating renewable energy into the grid would reduce variable costs by 19% each year, relative to the baseline system (HSIS, 2012). However, the estimated reduction in costs did not account for the capital required to integrate wind and solar energy into the grid (HSIS, 2012) and also failed to include the cost of the PPA and mitigation measures (HSIS, 2012).

The study analyzed technologies that would mitigate large fluctuations in current, including the battery energy-storage system (BESS) (HSIS, 2012). The study determined that a “BESS of approximately 24–30 MW was needed at each of the [central PV plants greater than] 100 MW” to “provide a 5% pu/min ramp rate functionality” (HSIS, 2012). The energy rating for the BESS would need to be between 16–18 min (HSIS, 2012). If the ramp rate could be reduced, the operating reserves on the system could also be reduced (HSIS, 2012). If the rate were reduced from 5% pu/min to an aggressive .8% pu/min, the spinning reserves would be reduced by approximately 40 MW, a reduction of 17% (HSIS, 2012). These calculations were made with the assumption that the annual energy demand for the Oahu system is 8,084 GWhr, with a system peak of 1,263MW (HSIS, 2012).

C. THE GALWAY REPORT

The Galway report was commissioned by HECO to investigate feasible options for establishing an LNG-import terminal in Hawaii. The report found that LNG suppliers factored in the risk of physical damage to a ship when quoting LNG delivery costs (Galaway, 2013). The premium charged for this risk was approximately $1 per MMtu, or approximately 25% more in shipping and regasification costs (Galway, 2013). Table 3 shows that delivered LNG costs are significantly higher with an offshore buoy configuration (highlighted in green) as compared to dockside configurations (Galway, 2013).

Table 3. Regasification and Shipping Economics (from Galway, 2013)

		Annual Volumes (MTPA)					
Terminal Configuration	Supplier	0.85	0.65	0.525	0.55	0.4	0.275
Onshore LNG Terminal	Kitimat	4.70	5.93	7.18	7.15	9.57	13.60
	US Gom	5.80	7.54	7.96	8.40	10.77	15.61
	Jordan Cove	4.84	6.33	7.84	7.75	10.66	15.49
	E. Australia	4.98	6.21	7.46	7.43	9.85	13.88
Small Scale Onshore	Kitimat	4.30	4.53	5.20	5.99	7.01	8.75
	Jordan Cove	4.15	4.41	4.91	6.54	6.98	8.38
2 x FSRU - Double Buoy	Kitimat	3.39	4.44	5.51	5.41	7.46	10.89
	US Gom	4.92	4.81	5.62	5.53	7.57	11.00
	Jordan Cove	3.43	4.48	5.56	5.47	7.50	10.94
	E. Australia	3.31	4.36	5.43	5.35	7.38	10.81
2 x FSRU - Single Buoy	Kitimat	3.19	4.19	5.20	5.11	7.07	10.29
	US Gom	4.72	4.56	5.31	5.23	7.18	10.40
	Jordan Cove	3.23	4.23	5.25	5.17	7.11	10.34
	E. Australia	3.11	4.11	5.12	5.05	6.99	10.21
Dockside Fullsize FSRU	Kitimat	2.56	3.13	3.71	3.69	4.81	6.68
	US Gom	3.66	4.74	4.49	4.94	6.01	8.69
	Jordan Cove	2.70	3.53	4.37	4.29	5.90	8.57
	E. Australia	2.84	3.41	3.99	3.97	5.09	6.96
Dockside Small/Mid FSRU	Kitimat	3.77	3.84	4.35	5.18	5.89	7.13
	Jordan Cove	3.62	3.72	4.06	5.73	5.86	6.76
ATB Regas Barges	Kitimat	4.30	5.86	5.28	7.05	7.46	10.13
	Jordan Cove	4.41	4.90	5.36	6.92	7.72	9.18

The following points from the Galway study summarize its salient concepts:

Supply risk is not anticipated to be an issue for HECO due to growing liquefaction capacity but managing price risk could be a key issue.

There are three procurement options:

1. Buy long-term supplies from a traditional supplier at oil indexation.
2. Buy from the spot market.

3. Contract for U.S. liquefaction tolling capacity (and buy gas from U.S. grid)

HECO's demand for LNG is small, which may limit its negotiation leverage as well as procurement options

Near shore floating LNG terminal options are viable but may face significant permitting challenges.

Although offshore floating options could be viable, additional study is required to confirm this.

Shipping strategy is driven by supply strategy and regasification configuration. U.S. Sourced supplies are likely to necessitate HECO's entry into the shipping business due to the Jones Act compliance requirements.

There appears to be a significant positive burner tip price spread between HECO's [Low Sulfur Fuel Oil] LSFO/ [Low Sulfur Diesel] LSD and U.S. LNG costs. There may be a positive price spread against global oil indexed LNG prices as well.

Galway believe there to be sufficient viability to further investigate LNG as an alternative fuel

Galway recommends that the next step should be to further define project scope and confirm technical and regulatory viability. This can be accomplished by undertaking the following tasks:

Commission detailed siting studies to assess the viability of offshore buoy based options. This could take 3 to 6 months with costs ranging from $0.5 to $1 million.

HECO should initiate discussions with the U.S. Navy to assess the viability of locating a FSRU based terminal in Pearl Harbor.

Develop regulatory and permitting strategy through informal consultations with federal and state regulatory authorities.

Develop detailed commercial and business structure for LNG importation.

Hold informal consultations with vendors and suppliers. (Galway, 2013)

Another major consideration in establishing an LNG-import terminal is the longevity of the terminal. The Galway study estimates import scenarios of .85, .65, and .525 millions of tons per annum (mmtpa) for the first ten years and .55, .4, and .275

mmtpa for the following ten (Galway, 2013). In essence, the Galway study forecasts a reduction in LNG volumes of 35%, 38%, and 47%, respectively in the first ten years of production (Galway, 2013). Therefore, the Navy must carefully examine long-term plans for the import terminal and commission a disposal-cost study before committing to a contract.

An additional factor that must be considered is whether to build the LNG-import terminal onshore or afloat. (Either approach must accommodate regasification, or re-gas, the process of converting liquefied natural gas to natural gas at atmospheric temperature.) The Galway report summarizes the two options as shown in Table 4 (Galway, 2013).

Table 4. On Shore vs. Off Shore Regasification Facility (after Galway, 2013)

Onshore	Floating
Marine facilities (berth, jetty)	Mooring system
1 or more steel & concrete tanks (typically 160,000 to 200,000 m3)	Modified LNG ship with vaporizers, additional utilities (FSRU)
Industry "standard"	Emerging, but increasingly accepted
Cost $ 0.5-1.5+ Billion	Cost: FSRU $100-250+ MM (Conv. Vs. New)
	Infrastructure $50-200+ million
Extensive history of reliable operations	Unit costs can be higher depending on throughput
Require deep water port (42 feet) & protected water for base load service	Require deep water port (42 feet) & protected water for base load service
Construction: 3-4 years	Construction: 3-12 moths infrastructure
Generally supports larger loads	12-30 months FSRU
US federal permitting: ~ 3 years	US Federal Permitting: 2-3 years

Capital costs may vary from $0.5–$1.5 billion based on the size and configuration of structures used in high-volume situations (Galway, 2013). Economies of scale are essential in onshore regasification terminals for companies to recoup the costs of service, debt servicing, and taxes (Galway, 2013). HECO is not likely to benefit unless significant economies of scale from an onshore gas facility can be achieved (Galway, 2013).

Floating storage and regasification units (FSRUs) may result in significantly less expensive upfront costs and may prove more cost effective in situations with low economies of scale (Galway, 2013). Additionally, floating solutions are easier to implement, both in construction costs and permitting (Galway, 2013). Onshore regasification permits issued by the Federal Energy Regulatory Commission can take three to four years (Galway, 2013). The U.S. Coast Guard is responsible for permitting offshore terminals and has streamlined the process to less than a year (Galway, 2013).

For berth-based floating terminal solutions, “Kalaeloa Harbor and Pearl Harbor may be the only viable sites” (Galway, 2013). Kalaeloa Harbor is well protected, with relatively deep water (38 feet), and is close to HECO’s plants and the hub of the fuel-pipeline distribution infrastructure (Galway, 2013), though the distribution infrastructure may need to be expanded to accommodate more gas (Galway, 2013). “Met-ocean conditions are a key determinant of the feasibility of floating LNG solutions” (Galway, 2013). Further study is needed to determine whether Kalaeloa Harbor conditions are sufficiently mild (Galway, 2013). “From a functional perspective, [Pearl Harbor] is likely to be the best site as it is protected, in calm waters and closer to major power and gas load customer” (Galway, 2013).

Floating options using ship-to-ship (STS) transfers may not be feasible in Hawaii because of the turgid sea state. Unlike U.S. Navy ships, LNG ships conducting STS transfers do not typically transfer gas while underway (moving through the water). STS occur mainly between two ships physically fastened via mooring lines. In 2013, FSRU STS transfers were conducted while docked 95% of the time (Galway, 2013).

Offshore Hawaii has unfavorable sea conditions for STS transfers (Galway, 2013). The report states that a historical analysis of the sea state off the coast of Hawaii in the vicinity of Barber’s Point showed sea conditions as satisfactory only 14% of the year, due primarily to the periodicity of the sea state’s exceeding 8 seconds (Galway, 2013). Galway determined that STS “seems unlikely to be feasible” (Galway, 2013).

Kalaeloa Harbor and offshore Barbers Point are two locations under consideration for an LNG-import facility (Galway, 2013). Table 5 shows both feasible and unfeasible options.

Table 5. Summary of Options for Regasification Infrastructure (after Galway, 2013)

	"Standard" Scale Solutions	Small/Mid Scale Solutions
Shore Side in Kalaeloa Harbor	FSRU with Single Berth & "Ship-to-Ship" LNG transfer FSRU with Double Berth & "Across the berth" LNG transfer	Mid Scale FSRU with Single Berth & "Ship-to-Ship" LNG transfer Mid Scale FSRU with Double Berth & "Across the berth" LNG Transfer Regas ATB Barge with Single Berth
Offshore Barbers Point or Kahe Point	FSRU with Single Submerged Mooring Buoy with STS FSRU with Above Water Single Point Mooring (fixed or floating) with STS 2 FSRU's with Single Submerged Mooring Buoy 2 FSRU's with Double Submerged Mooring Buoys	Mid Scale FSRU with Single Submerged Mooring Buoy with STS Mid Scale FSRU with Above Water Single Point Mooring (fixed or floating) with STS Regas Barges with Single Submerged Mooring Buoy

Green: these solutions appear feasible pending further siting considerations

Orange: there are concerns about viability because of met-ocean conditions and lack of a track record (these have never been implemented)

Red: these are unlikely because of STS challenges and the lack of supplier acceptance

While several of the options in Table 5 are feasible pending further siting considerations, Pearl Harbor is presently considered the best option (Galway, 2013). The Galway report wrote states,

> Pearl Harbor seems to be the best site for a Hawaii LNG terminal. The site is protected is in calm water and would likely require little dredging. Further, it is close to major load centers for power HECO and local gas companies. Presumably, it could also provide ancillary benefits to the U.S. Navy Base (Galway, 2013).

The Galway report notes that "Kalaeloa Harbor is seen as a viable fallback siting option, but obtaining the required permits and approval will require stakeholder consent and input" (Galway, 2013). The major problems with Kalaeloa Harbor are:

- **Berth availability** “Kalaeloa Harbor is a busy commercial port with limited berth availability.” The Hawaii Department of Transportation, Harbor Division, must be consulted with regard to terminal expansions (Galway, 2013).

- **Harbor dredging** “Dredging would be required to accommodate standard LNG ships and berthed FSRUs” (Galway, 2013). The estimated dredging cost would range from $5 million to $10 million. Additionally, land-based excavation would also be required, with an estimated cost between $6 million to $20 million at one potential location in Kalaeloa Harbor (Galway, 2013). Removal of dirt also requires an environmental impact study under the NEPA process administered by the FERC permitting process, which increases time and expense (Galway, 2013). However, dredging would be minimized or eliminated with a small or midscale LNG solution either onshore or floating (Galway, 2013).

- **Security zones** The Coast Guard mandates the placement of security zones on a site-by-site basis for LNG vessels both underway and moored (Galway, 2013). Merchant traffic and pleasure boaters may have substantial opposition to LNG permitting in Kalaeloa Harbor (Galway, 2013). Additionally, residential homes would likely fall within an exclusion zone, which are “determined through modeling and are dependent on site specific characteristics such as prevailing temperatures, humidity, wind speed and direction, topography” (Galway, 2013).

D. FACTS OF GLOBAL ENERGY

FGE was contracted in 2012 to conduct an analysis of the LNG market for Hawaii. The study primarily focused on market conditions for LNG and sourcing possibilities and financial benefits of building an LNG-import terminal (FGE, 2012). Obtaining LNG from the right supplier is a primary driver behind the economics of an LNG-import terminal on Hawaii. One advantage Hawaii has in sourcing fuel from one of

the new American LNG-export terminals is that the import terminal would be exempted from DOE approval because the shipment would be considered interstate trade rather than legal exporting (FGE, 2012). However, since the trade would be interstate, the Jones Act would apply (FGE, 2012), requiring “trade between two U.S. ports to be carried on U.S.-built, U.S.-flagged ships, and the crew must be three-quarters comprised of U.S. merchant seaman” (FGE, 2012). Currently, all LNG ships built in the United States are flagged abroad (FGE, 2013). Therefore, American ships would have to be purchased new or reflagged (FGE, 2012).

An additional problem stems from the fact that all LNG ships, even the smallest, are rated at a capacity of 57,000 tonnes of LNG at 90% of their deadweight tonnage (DWT, the total weight of cargo that a ship can transport) (FGE, 2012) (FGE, 2012). For security of supply, at least two of these ships would have to be engaged (FGE, 2012). The pair of hypothetical ships would supply 2.2 million tons of LNG per year, or a million tons if traversing from Australia to the Gulf Coast (FGE, 2012). The Galway study expects .85 million tons per annum on the high side and, on the low end, .525 tons per year (Galway, 2013). Additionally, the demand is expected to decrease 35%–47% by the eleventh year (Galway, 2013).

American LNG ships were all built prior to 1980, making replacement a consideration (FGE, 2012). However, it is widely held that the industrial infrastructure for building an LNG cargo ship to replace aging ships no longer exists in the United States (FGE, 2012). One possible substitute is LNG barges that have been built outside the U.S. (FGE, 2012). The Coast Guard has deemed foreign LNG barges Jones-Act exempt, providing that “the LNG containment vessels are not an integral part of the hull” (FGE, 2012). Further investigation is required to determine whether an FSRU could receive a Jones-Act waiver (FGE, 2012).

Table 6 shows shipping costs from several LNG-import terminals and highlights how these costs can vary by large percentages, depending on where the LNG is sourced. The importance of shipping strategy in the overall economic analysis of the LNG-import terminal is also suggested.

Table 6. LNG Tanker Shipping Costs (from FGE, 2012)

Figure 43: LNG Tanker Shipping Costs

	Alaska* Valdez	Australia NW Shelf	Canada Kitimat	US West* Astoria	US Gulf** Sabine Pass
Distance, nm	2,462	5,840	2,350	2,246	6,100
Cost, $/mmBtu	$ 1.92	$ 4.03	$ 1.85	$ 1.78	$ 4.41

*requires Jones Act waiver

**requires Jones Act waiver; includes Panama Canal tolls

According to the FGE report,

> Offshore storage and gasification along the model of the single tending line (STL) buoy system may in fact be a poor idea for Hawaii, irrespective of delivery economics. Once the LNG gas reassumes a gaseous form, many options become impractical. Yes, gas onshore on Oahu can feed power plants and existing Hawaii Gas SNG customers, but it eliminates many of the other possible usages of LNG such as road transport and marine bunkering. LNG may also be the best way to deliver gas for CNG filling stations (FGE, 2013).

The cost of converting diesel plants to LNG must be carefully considered (FGE, 2013). Plants in Puerto Rico have been retrofitted as dual-firing plants that burn either LNG or diesel at any given time (FGE, 2012). Technology vendors consulted in the FGE study indicate that the cost of fitting a new power plant for dual firing would cost $500,000 per unit, and the cost of retrofitting an existing plant would be nearly $1 million (FGE, 2012). The main consideration is the cost per kWh. For a plant like Kahe, which has six units, the retrofit would cost approximately $6 million (FGE, 2012). If the plan maintains a 60% utilization rate, the cost per kWh for retrofitting to dual firing is less than 0.02 cents (FGE, 2012). The FGE study further concluded that the retrofitting cost per kWh could be higher in lower-capacity, less-utilized plants, but was not likely to exceed 0.1 cents/kWh. Therefore, the cost of retrofitting a plant is negligible compared to fuel, shipping, and capital-investment costs.

III. METHODOLOGY AND RESEARCH APPROACH

A. INTRODUCTION

Many variables and models must be considered when analyzing multi-million-dollar energy projects. Assumptions for developing the NPV and CBA are clarified in this chapter, followed by explanations of calculations and formulas for each model.

B. PEARL HARBOR SOLAR-PV ANALYSIS

The NPV for Solar PV has been calculated over a 30-year timeframe with a scheduled system upgrade of $20 million ($400/installed kW) at year fifteen and an additional upgrade of $12.5 million ($250/ installed kW) at year seventeen to address any degradation in panels, wiring, or invertor performance. These assumptions are best estimates; however, a higher fidelity model can be employed based on inputs from the actual performance and miscellaneous costs of the solar-PV system at Waipu, once installed (CNRH, 2014). The net-present-value method compares the benefits of owning a solar-PV system and the option of a PPA, while considering the time value of money.

Table 7. Solar PV NPV Assumptions

Metric	Quantity	Reference
System Capacity (kw)	50,000	(CNRH, 2014a)
Efficiency / usage	22%	(HSIS, 2012)
kWh/day	264,000	
kWh / year	96,360,000	
$/kWh electricity cost avoided	0.28	(CNRH, 2014b)
Electricity price increase annually	2%	
Avoided electricity cost per year	$ 269,808	
System Cost (3.10 $/kwh)	$ 155,000,000	(SOLSYSTEMS, 2014)
Annual maintenance cost	$ 2,000,000	
Discount rate	1.90%	(OMB, 2013)
Annual Inflation rate	2%	
Maintenance cost $/kW-yr	$ 40.00	(EPRI, 2010)
Output degradation per year	0.5%	(Jordan, Smith, Gelak, Kurtz, and Oserwarld, 2010)

1. 50-MW Solar-NPV Assumptions at West Loch

The assumptions in Table 8 have been used to develop the 50-MW solar-PV NPV (see Appendix A) and evaluate the best course of action for CNRH. The assumptions were generated from the information provided by CNRH and the most relevant published data. The system capacity was selected by CNRH (CNRH, 2014b). While 50 MW was used for the base-case assumption, system capacity may change before contract finalization.

An efficiency and usage percentage of 22% was obtained from a local report commissioned by HECO for various amounts of solar efficiency per location on Oahu (HSIS, 2012). The stated 22% for efficiency (usage) is specific to the Pearl Harbor area and is considered a high-fidelity estimate (HSIS, 2012).

The $0.28/kWh was obtained directly from CNRH (CNRH, 2013). CNRH paid HECO/KIUC $0.272/kWh on average in FY2013 for all electricity used within the NAFAC regional fence line (B. Law, email to author, October 24, 2014). Therefore, $.28/kWh reflects a conservative estimate for the CNRH utility rate, which has shown a strong historical trend of increasing.

A 2% annual electricity price increase was used as an estimate that roughly mirrors expected inflation and the average annual PPA rate increase for Hawaii (Solsystems, 2014).

The 50MW system cost was determined by multiplying the capacity of the system (50,000 kW =50MW) by the expected $3.10W(dc) for an upper estimate of the utility-scale projects in Hawaii (Solsystems, 2014). This amount is corroborated by a recent Sun Shot report observing that U.S. solar prices for a utility-scale c-Si fixed-tilt in 2013–2014 averaged $3.0 W (dc) (Barbose, Galen, Weaver, and Darghouth, 2014). Therefore, $3100 kW (dc) or $3.10 W (dc) was used for the base-case assumption.

Systems maintenance costs were assessed at $40/kW-year with an increase in costs of 2% per year, totaling $2 million for the first year. $40/kW-year was generated from an EPRI report that asserted total O&M costs as $47 /kW-yr (EPRI, 2010). Table 8

shows the costs of ground-mounted, fixed-tilt solar panels made of monocrystalline (c-Si) panels (EPRI, 2010). The price breakdown is as follows:

Table 8. Utility-Scale Solar PV Power Plant O&M Costs Estimates (after EPRI, 2010)

O&M Costs ($/kw-yr)	Fixed-Tilt c-Si
Scheduled Maintenance/Cleaning	20
Unscheduled Maintenance	2
Inverter Replacement Reserve	10
Subtotal O&M	32
Insurance, Poperty Taxes, Owner's Costs	15
Total O&M	47

The O&M cost estimates seem extremely conservative. Costs such as scheduled maintenance/cleaning, unscheduled maintenance, and inverter-replacement reserve certainly apply to the West Loch solar PV project; however, costs such as insurance and property taxes do not, if the Navy chooses to purchase the system and not pursue a PPA. Accordingly, only $8 ($/kWh) of the insurance, property taxes, and owners's costs were allocated to the total O&M costs. Therefore, the working number for analysis is 40 rather than 47 ($/kWh-yr).

Degradation of system capability was also considered. According to a report entitled "Outdoor PV Degradation Comparison" by Jordan, Smith, Gelak, Kurtz, and Osterwald, the median degradation of solar PV panels over time was 0.5% per year after comparing 40 different modules from ten different manufactures with a minimum degradation assessment time of two years (2010). All the panels assessed were installed before 2008, and several before 2000 (Jordan, Smith, Gelak, Kurtz, and Oserwarld, 2010). In their findings, the authors report that panels produced after 2000 show considerably less degradation than panels produced before (Jordan, Smith, Gelak, Kurtz, and Oserwarld, 2010). Since older panels were included in the population sample that resulted in a 0.5% median degradation, 0.5% appeared to be a fairly conservative estimate, taking into consideration the age of the solar-PV technology, recent

advancements in PV technology, and the ability to choose panels that demonstrate lower degradation.

2. Solar Methodology

Solar PV was evaluated in two ways. The first way was to determine the NPV over 30 years. The second way was to determine the number of years for the investment to break even.

a. NPV of Solar PV over Different Investment Costs

The cost of solar PV is not a fixed price. While indications are that utility-scale solar prices bottomed out in 2012 and 2013, each individual project is different (Barbose, Galen, Weaver, and Darghouth, 2014). Therefore, a particular emphasis was made to evaluate the NPV over a range of installed costs in 2013 dollars, from $2.70 to $3.70 per Watt (dc) (Barbose, Galen, Weaver, and Darghouth, 2014). Analysis over a broad range of installed costs allows more relevant estimation of pricing predictions.

b. Break-Even Analysis

A break-even analysis was conducted to estimate the first year solar PV would have a positive NPV. The values were discounted at the OMB real discount rate of 1.9% for projects with a life cycle of 30 years.

3. Solar PV Sensitivity Analysis

Solar-PV sensitivity analysis was conducted for both changes in cost savings and efficiency or performance over time. The cost savings were evaluated at three values: $0.28/ kWh, $0.19/ kWh, and $13.3/ kWh. $0.28/kWh was used under the assumption that either a net-metering situation would exist or a micro-grid could be installed to completely avoid the utility-rate costs. This situation is unlikely to occur, since the PUC allows for net metering on less than 100-kW systems only (HECO, 2014a). Therefore, utility-scale systems such as the proposed project at West Loch would not qualify for net metering. Additionally, CNRH contributes 6.5% of gross revenue for Hawaii Electric Industries (HEI) and all of HEI’s subsidiaries, according to the 2013 consolidated 10-K

(B. Law, email to author, October 24, 2014) (HECO, 2014b). It is highly unlikely that HECO could sustain such large losses in revenue, considering the relatively small margins authorized by the PUC.

Utility-scale projects must be repaid at a rate of no less than 100% of the utility avoided energy cost, which was \$0.19/kWh for 7/1/2014 (HAR 6–74-22) (HECO, 2014a). Therefore, the second rate analyzed was \$0.19/kWh to capture minimum avoided energy costs that would be paid by HECO to a utility-scale IPP.

The final rate analyzed was \$0.133/kWh, because it captured the savings that HECO predicted might be expected if an LNG-import terminal were installed. HECO reported to CNRH that an LNG-import terminal would result in a 20%–30% reduction in utility rates (CNRH, 2014b), as in the equation below.

$$\frac{\$0.19}{kwh} * (1 - 30\%) = \frac{\$0.133}{kwh}$$

Three different efficiencies were chosen for sensitivity analysis. The base case chosen was 22% in accordance with the HECO-commissioned HSIS report. Additionally, efficiencies of 18% and 28% were analyzed, based on the approximated minus- and plus-two cents in the levelized cost of energy (LCOE), respectively.

C. A POTENTIAL LNG TERMINAL

An LNG-import terminal could be a significant benefit to CNRH and all utility ratepayers. While many locations might work for an LNG terminal, the Pearl Harbor terminal was cited as the best location by the FGE and Galway reports (FGE, 2012) (Galway, 2013). Both reports cited the offshore terminals as likely unfeasible or requiring further investigation, due to technical difficulties involving sea state (FGE, 2012) (Galway, 2013). Besides Pearl Harbor, the only other onshore LNG terminal possible is Kalaeloa Harbor, the main commercial port for Oahu.

1. Zone of Possible Agreement

A zone of possible agreement (ZOPA) is the bargaining range in which two parties are willing to conduct business (Spangler, 2013), based on the concept that both

parties have already established their best alternative to a negotiated agreement (BATNA), or best alternative option (Rogers and Ury, 2011). Figure 6 depicts how a ZOPA can be used.

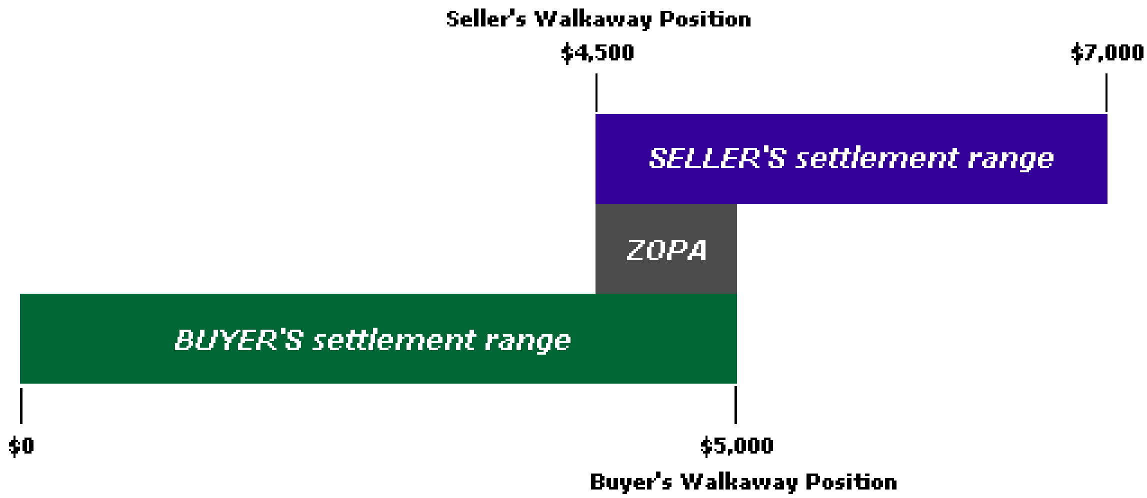

Figure 6. ZOPA (from Spangler, 2013)

This figure may also describe real negotiations with fictitious numbers. Assume CNRH is the seller and HECO the buyer, though HECO is currently pursuing CNRH to reach an agreement. According to Figure 6, the seller (CNRH) is not willing to lease the land for less than a fictitious $4,500, because the land could be leased to an outside entity for no less than $4,500. Therefore, CNRH's BATNA is $4,500. The buyer (HECO) is not willing to lease the land for greater than $5,000 because that is the cost of a lease at Kalaeloa Harbor, which would have equal operating costs. Thus, HECO's BATNA is no greater than $5,000.

2. Galway Report LNG NPV

The LNG NPV is conducted from the prospective of HECO. While it is impossible to account for all of the factors that would contribute to the costs of an LNG-import terminal, the LNG NPV is extremely useful in understanding HECO's willingness to pay for the LNG land lease at Pearl Harbor. The FGE report cites the expected cost to retrofit a diesel generator so that it can also be used with LNG (FGE, 2012). The FGE

report also provides estimates for the cost of the piping infrastructure required to transport LNG from an import terminal to the HECO power facilities (FGE, 2012).

The Galway report gives estimates for the commodity and transportation costs to Oahu of several of the most viable options and provides a range of costs for a floating storage re-gas unit (FSRU)—plus the infrastructure required to safely moor the unit in the harbor.

Based on the numbers generated from the FGE and Galway reports, an NPV could be conducted with the assumptions listed in Table 9.

Table 9. Galway LNG NPV Assumptions

Type of Factor	Impact	Reference
Consumption of LNG (MTPA)	0.65-0.40 mtpa	Quantity decreasing over 10 Years (Galway, 2013)
Conversion factor of MPTA to mmBTU	49257899.06	1 mpta= 49257899.06 mmBTU
Aquistion and transportation cost of LNG ($/mmBTU)	13.62-15.89	Price increasing linearly from the forecast (FGE, 2012)
Equivalent LS Diesel Cost ($/mmBTU)	25.63-25.874	Price increasing linearly from the forecast (FGE, 2012)
Inflation (Discount Rate)	2%	Projected Inflation

The consumption of LNG was derived from the Galway report, in which 0.65 mpta was the midpoint value of three estimates in the "HECO Re-gas Economic Analysis" (Galway, 2013). Additionally, the model is centered at 0.55 mpta, which is the figure HECO communicated to CNRH as the approximate capacity of the LNG terminal (CNRH, 2014b). The Galway model demonstrated a decreasing consumption of LNG from 0.65 mpta a year in 2020 to 0.40 mpta a year in 2030 (Galway, 2013).

The reduction in LNG consumption would be consistent with HECO's commitment to achieving the Hawaii Clean Energy Initiative mandate of 40% renewable energy by 2030. Therefore, this report modeled a linear reduction in LNG consumption in Year 1 (2021) 0.65 mpta to Year 10 (2030) 0.40 mpta.

The base-case acquisition and transportation costs of LNG were obtained from the FGE report entitled "USWC Delivery Build-Up, 2012 $/mmBtu (Tanker Delivery)," which is summarized for this report in Table 10 (FGE, 2012). USWC refers to the United

States west coast, where LNG will likely be exported from terminals such as Jordan Cove (FGE, 2012).

Table 10. Cost of Delivered LNG in $/mmBTU (after FGE,2012)

USWC Delivery Build-Up, 2012 $/mmBtu (Tanker Delivery)

	2015*	2020	2025	2030
EIA Henry Hub	4.46	4.76	5.86	6.54
x 115%	5.13	5.48	6.73	7.52
+ Liquefaction, 1,000/tpa	3.5	3.5	3.5	3.5
=FOB Price	**8.63**	**8.98**	**10.23**	**11.02**
+Tansport & Boil-off	1.96	1.99	2.11	2.18
+Onshore Costs	2.38	2.38	2.38	2.38
+Regas Loss	0.26	0.27	0.29	0.31
=Delivered Cost	**13.23**	**13.62**	**15.01**	**15.89**

*Notional; no major export capacity 2015

Table 11. Comparison in Delivered Cost of LNG to LSFO and LS Diesel (after FGE, 2012)

Delivery Build-Up, 2012 US $/mmBtu (FGE Oil Prices)

	2015	2020	2025	2030
Alaska	na	na	$ 23.12	$ 23.10
Australia	$ 23.51	$ 23.70	$ 24.46	$ 24.43
Canada	na	$ 20.24	$ 20.91	$ 20.89
US Gulf Coast	$ 16.19	$ 16.63	$ 18.22	$ 19.22
US West Coast	na	$ 13.62	$ 15.01	$ 15.89
Hawaii LSFO	22.08	$ 23.28	$ 22.88	$ 21.79
Hawaii LS Diesel	22.99	$ 25.17	$ 26.07	$ 26.25

The onshore cost of $2.38 by the FGE group amounts to $79 million a year at 0.65 mtpa and $50 million a year at 0.40 mpta. These costs are consistent with this report's independent analysis of $57 million per year, with the assumptions found in Table 12.

Table 12. Moored LNG FSRU Costs

Type of Factor	Impact	Reference
Cost for FSRU (millions)	$175	(Galway, pg N-73)
Import Terminal Facility (millions)	$125	(Galway Report, pg N-73)
Retro Fitting Generators (millions)	$20	(FGE, pg 104)
Piping Costs (millinos)	$84	(FGE, pg 104)
Total Projected infastructure Costs (millions)	$404	Subject to Sensitivity Analysis
Projected WACC for consotrium	7.33%	Based off Shell WACC

The $404 million amortized over ten years with an interest rate of 7.33% equates to $57 million annually (Stock Researching, 2014). HECO is unlikely to finance the project itself, due to lack of expertise and an extremely high cost of capital stemming from its BBB- credit rating (Hawaii Electric Industries, Inc., 2014).

The 7.33% interest rate in Table 12 is obtained from the weighted average cost of capital of Royal Dutch Shell, which could serve as a possible consortium for the investment, having both technical expertise and a credit rating significantly higher than HECO's (Stock Researching, 2014). The rate of 7.33% is more applicable than the interest rate for financing that Shell could obtain, because Shell would need to generate an ROI that would satisfy shareholders. These factors are considered in the weighted average cost of capital (WACC) (Stock Researching, 2014).

The "revenue" in the NPV was assessed in avoided fuel costs or the difference from the forecasted LS diesel price and the forecasted LNG delivered-to-the-power-plant cost. The forecast for LS diesel by FGE from year 2020–2030 is seen as more conservative than EIA estimates, because rises in prices vary little over the decade (FGE, 2012). The forecast for LNG prices is also based on the Henry Hub system, which considers the additional provisions listed in Table 12.

The added transportation cost allows LNG to be compared to LS diesel, which can be procured on Oahu from oil refineries without significant transportation costs or physical losses. Additionally, sunk costs in LS-diesel infrastructure are not included. The 2% inflation rate was used to discount the cash-flow differential between LS diesel and LNG costs only. The forecasted price of LS diesel and LNG accounted for inflation;

therefore, the 2% increase was not applied. The cumulative analysis of the NPV will serve as a metric to determine the upper boundary of HECO's willingness to pay. That upper boundary can be used as the key upper limit in the ZOPA model for determining a fair land lease.

3. Economics of Pearl Harbor LNG Terminal Alternatives

The Galway report states in its conclusion that "Pearl Harbor is the best choice" for a regasification terminal of all sites evaluated (Galway, 2013). The "next best option would be an offshore floating option with shuttling FSRUs, but additional study is required to confirm" (Galway, 2013). The third option is a "near-shore floating option at Kalaeloa Harbor" (Galway, 2013). However, the Kalaeloa Harbor viability is dependent upon "permitting challenges" and "stakeholder issues" being satisfactorily overcome (Galway, 2013).

This section evaluates the economic benefits of one re-gas option over another and analyzes the re-gas and transportation costs for different type of facilities, over different LNG volumes, without considering commodity cost. Table 13 employs values from the Galway report and Table 14 transforms the $/mmBtu units from Table 13 into total costs. The conversion rate used was 49,257,899.069 mmBtu = 1 mpta. The total costs were measured against each other to determine empirically the value of each alternative.

Table 13. Re-gas and Shipping Economics (after Galway, 2013)

		Annual Volumes (MTPA) (Prices are in $/mmBTU)					
Terminal Configuration	**Supplier**	**0.85**	**0.65**	**0.53**	**0.55**	**0.40**	**0.28**
Onshore LNG Terminal	Kitimat	4.70	7.15	5.93	9.57	7.18	13.60
	US Gom	5.80	6.31	5.48	5.95	5.90	6.71
	Jordan Cove	4.84	5.10	5.36	5.30	5.79	6.59
	E. Australia	4.98	4.98	4.98	4.98	4.98	4.98
Small Scale Onshore	Kitimat	4.30	5.06	4.67	7.03	5.97	8.75
	Jordan Cove	4.15	4.94	4.38	7.58	5.94	8.38
2 x FSRU - Double Buoy	Kitimat	3.39	5.09	4.88	6.62	6.23	10.89
	US Gom	4.92	5.46	4.99	6.74	6.34	11.00
	Jordan Cove	4.43	5.13	4.93	6.68	6.27	10.94
	E. Australia	3.31	5.01	4.80	6.56	6.15	10.81
2 x FSRU - Single Buoy	Kitimat	3.19	4.79	4.63	6.23	5.92	10.29
	US Gom	4.72	5.16	4.74	6.35	6.03	10.40
	Jordan Cove	3.23	4.83	4.68	6.29	5.96	10.34
	E. Australia	3.11	4.71	4.55	6.17	5.84	10.21
Dockside Fullsize FSRU	Kitimat	2.56	3.69	3.13	4.81	3.71	6.68
	US Gom	3.66	5.30	3.91	6.06	4.91	8.69
	Jordan Cove	2.70	4.09	3.79	5.41	4.80	5.57
	E. Australia	2.84	3.97	3.41	5.09	3.99	6.96
Dockside Small/Mid FSRU	Kitimat	3.77	4.25	3.98	5.91	6.12	7.13
	Jordan Cove	3.62	4.13	3.69	6.46	6.09	6.76
ATB Regas Barges	Kitimat	4.30	6.32	4.81	7.96	6.56	10.13
	Jordan Cove	4.41	5.36	4.89	7.83	6.82	9.18

Table 14. LNG Commodity Prices Generated after Galway Report

		Total Price for Various Annual Volumes (MTPA) and Supplier Locations					
Terminal Configuration	**Supplier**	**0.85**	**0.65**	**0.53**	**0.55**	**0.40**	**0.28**
Onshore LNG Terminal	Kitimat	$ 196,785,306.78	$ 228,926,085.92	$ 154,812,650.98	$ 259,268,951.75	$ 141,468,686.13	$ 187,574,079.65
	US Gom	$ 242,841,442.41	$ 202,031,273.03	$ 143,064,642.06	$ 161,196,474.70	$ 116,248,641.80	$ 92,545,740.77
	Jordan Cove	$ 202,646,996.77	$ 163,289,935.41	$ 139,931,839.68	$ 143,586,775.79	$ 114,081,294.24	$ 90,890,675.36
	E. Australia	$ 208,508,686.76	$ 159,447,819.29	$ 130,011,298.80	$ 134,917,385.55	$ 98,121,734.95	$ 68,685,214.46
Small Scale Onshore	Kitimat	$ 180,037,621.10	$ 162,009,230.04	$ 121,918,225.99	$ 190,455,666.75	$ 117,627,862.98	$ 120,681,852.72
	Jordan Cove	$ 173,757,238.97	$ 158,167,113.91	$ 114,347,286.90	$ 205,356,181.22	$ 117,036,768.19	$ 115,578,734.38
2 x FSRU - Double Buoy	Kitimat	$ 141,936,636.17	$ 162,969,759.07	$ 127,400,630.15	$ 179,348,010.51	$ 122,750,684.48	$ 150,197,185.84
	US Gom	$ 205,996,533.91	$ 174,816,283.80	$ 130,272,365.67	$ 182,599,031.85	$ 124,918,032.04	$ 151,714,329.13
	Jordan Cove	$ 185,480,618.94	$ 164,250,464.45	$ 128,705,964.48	$ 180,973,521.18	$ 123,538,810.87	$ 150,886,796.43
	E. Australia	$ 138,587,099.03	$ 160,408,348.32	$ 125,312,095.23	$ 177,722,499.84	$ 121,174,431.71	$ 149,093,808.90
2 x FSRU - Single Buoy	Kitimat	$ 133,562,793.33	$ 153,364,468.75	$ 120,873,958.53	$ 168,782,191.16	$ 116,642,705.00	$ 141,921,858.80
	US Gom	$ 197,622,691.06	$ 165,210,993.48	$ 123,745,694.04	$ 172,033,212.50	$ 118,810,052.55	$ 143,439,002.09
	Jordan Cove	$ 135,237,561.89	$ 154,645,174.13	$ 122,179,292.85	$ 170,407,701.83	$ 117,430,831.38	$ 142,611,469.38
	E. Australia	$ 130,213,256.19	$ 150,803,058.00	$ 118,785,423.60	$ 167,156,680.49	$ 115,066,452.23	$ 140,818,481.86
Dockside Fullsize FSRU	Kitimat	$ 107,185,188.37	$ 118,145,070.92	$ 81,713,928.77	$ 130,311,771.99	$ 73,098,722.22	$ 92,131,974.42
	US Gom	$ 153,241,324.00	$ 169,693,462.29	$ 102,077,144.24	$ 164,176,577.60	$ 96,742,513.77	$ 119,854,320.01
	Jordan Cove	$ 113,046,878.36	$ 130,952,124.67	$ 98,944,341.86	$ 146,566,878.68	$ 94,575,166.21	$ 76,822,619.39
	E. Australia	$ 118,908,568.35	$ 127,110,008.55	$ 89,023,800.99	$ 137,897,488.44	$ 78,615,606.91	$ 95,993,793.71
Dockside Small/Mid FSRU	Kitimat	$ 157,846,937.57	$ 136,074,946.18	$ 103,904,612.30	$ 160,112,800.92	$ 120,583,336.92	$ 98,338,469.70
	Jordan Cove	$ 151,566,555.44	$ 132,232,830.05	$ 96,333,673.21	$ 175,013,315.39	$ 119,992,242.13	$ 93,235,351.36
ATB Regas Barges	Kitimat	$ 180,037,621.10	$ 202,351,449.38	$ 125,573,162.10	$ 215,651,082.12	$ 129,252,727.16	$ 139,715,104.92
	Jordan Cove	$ 184,643,234.66	$ 171,614,520.36	$ 127,661,697.02	$ 212,129,142.34	$ 134,375,548.66	$ 126,612,503.77

Best Price Per BTU

Best Price Per BTU Per Quantity

Best Pric Per BTU Per Qty. Per Terminal Configuration

4. Comparable LNG-Terminal Land Leases

The methodology used in estimating the fair value of the Pearl Harbor land lease was to find comparable LNG-terminal land leases and determine what they are paying. Table 30 provides the basis for a multivariable-regression analysis based on the specified parameter in tables 15 and 16.

Table 15. Comparable LNG-Terminal Land Leases

Location	Company
Port of Tacoma, WA	Puget Sound Energy
Port of Lake Charles, LA	Magnolia LNG
Warrenton/ Astoria, OR	Oregon LNG
Freeport, TX	Freeport LNG
Corpus Christi, TX	Cheniere
WA Port of Vancouver (Oil Terminal)	Tesoro & Savage

Table 16. LNG Land-Lease Metrics

Metric
Date
Acre
Yearly Capacity (MTPA)
Duration (yr)
Cost (Mil/yr)
2014 Dollars
Facility Cost (Mil)
Prop. Taxes (Mil)

5. LNG Expected Electricity Savings

HECO has communicated to CNRH that the expected savings in utility prices of an LNG-import terminal would range between 20%–30% (CNRH, 2014). Using publically available information, the Galway report attempted to verify those calculations. The HSIS report states that the Hawaii Integration Study Team "found that the Oahu grid could absorb all the available solar and wind energy" (904 GWh or 11% of

the annual load energy) (HSIS, 2012). By interpolation, it can reasonably be estimated that the annual demand for Oahu in 2011 was 8,218 GWh. 8,218 GWh is equivalent to 28,040,979 mmBtu. The proposed annual import quantity of LNG ranges from 0.55–0.65 mtpa of LNG and is equivalent of 28,040,979 mmBtu and 32,017,634 mmBtu of LNG, respectively. Therefore, we can reasonably conclude that HECO intends to replace all LS diesel use with LNG.

The following tables were used to verify that anticipated reductions in utility costs are feasible. The values in Table 17 were obtained directly from HECO’s 2013 annual financial report to the PUC and were used to calculate the percentage of consumed fuel in overall operating and maintenance expenses, as well as total operating expenses. The values are found in the bottom-right side of the table. Table 18 evaluates HECO’s claim that LNG could reduce CNRH utility prices by 20%–30%. The first step is to use the total cost of fuel consumed in 2013 and reduce it by 25%–50%, a range consistent with both the FGE and Galway report findings. The Galway report states that the cost difference between delivered prices of LS fuel oil and LNG amounts to 42% (see page N-84, scenario 3B), which is the greatest estimated cost savings (Galway, 2013). FGE report makes similar findings, stating that “savings compared to LSFO range from 27%–42%; compared to diesel, LNG saves 39%–46%” (FGE, 2012). Therefore, a reduction in fuel costs of 25%-50% is used as a basis for evaluation. Two comparisons were made using operating and maintenance expenses and total operating costs as the denominator. The numerator was obtained from projected savings using LNG. The output from the calculation was turned into a percentage, as seen in tables 17 and 18. The explanation is presented in Table 33.

Table 17. HECO's 2013 Annual Financial Report

	Amount	Percentage
Total Cost of Fuel Consumed in 2013	$ 827,800,958	
Maintence Expense	$ 76,521,565	
Operating Expense	$ 1,582,892,531	
Total Operating Expense	$ 2,007,528,107	
Fuel Consumed/ Operating & Maintenance Expense		49.89%
Fuel Consumed/ Total Operating Expense		41.23%

Table 18. Percent Reduction in Operating Expenses from LNG Usage

% Savings using LNG from LS Diesel	0.25	0.3	0.45	0.5
Savings from LNG Consumed	$ 206,950,240	$ 248,340,287	$ 372,510,431	$ 413,900,479.00
O&M Expense minus LNG Savings	$ 1,375,942,292	$1,334,552,244	$ 1,210,382,100	$1,168,992,052.00
Total Operating Expense- LNG Savings	$ 1,800,577,868	$1,759,187,820	$ 1,635,017,676	$1,593,627,628.00
% Change in Operating Expense	17.1%	19.6%	27.1%	29.6%
% Change in Total Operating Expense	10.3%	12.4%	18.6%	20.6%

IV. DATA ANALYSIS OF SOLAR PV

A. INTRODUCTION

This project calculates the potential savings of two potential projects: a 50-MW solar-PV field and an approximately 0.55-mtpa LNG-import terminal. The solar-PV system is considered from a Navy-owned perspective only, since the calculations for a PPA are fairly simple once a contract is available.

B. BASE-CASE ASSUMPTIONS AND DATA ANALYSIS

The real discount rate used in this research project is 1.0%, 1.6%, and 1.9%, for ten, 20, and 30 years, respectively, according to the OMB Circular A-94, as revised in December 2013 for calendar year 2014 (OMB, 2013).

C. NPV OF SOLAR PV OVER DIFFERENT INVESTMENT COSTS

The NPV of solar PV is an extremely helpful datum in deciding among projects. Figure 7 displays how the NPV changes based on different payback rates—the rates used in this analysis are $0.28kWh/ $0.19kWh/ $0.133kWh. The three lines represent the three most likely payback rates for electricity generated by solar-PV panels over a range of costs per panel, which excludes the costs of tying the panels into the grid (see Appendix A for NPV calculations). Figure 7 is useful in evaluating the benefits of ownership versus entering a power-purchase agreement and highlights the advantages of different payback-rate scenarios. Finally, this figure helps evaluate the dollar amount available for additional infrastructure, such as grid tie-ins, while still preserving a beneficial economic outcome.

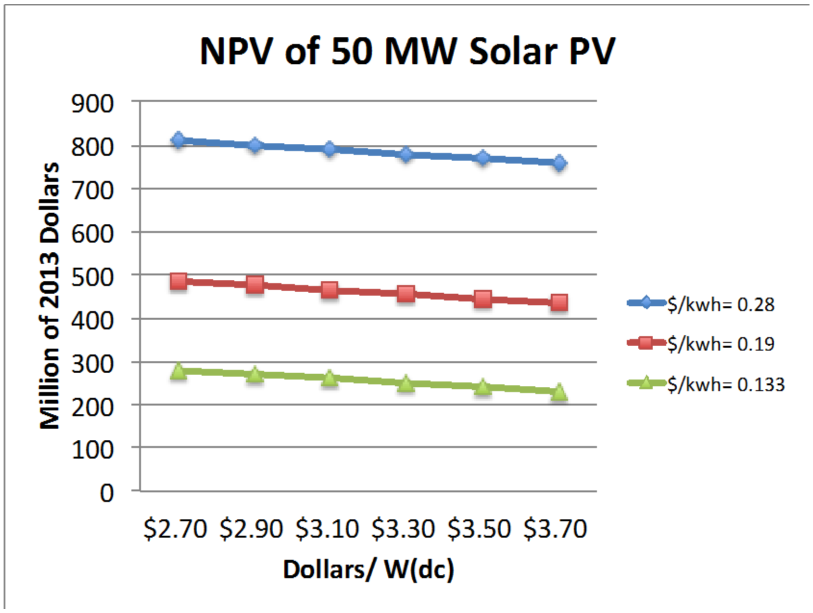

Figure 7. NPV of 50MW Solar PV

Table 19 highlights the benefits of replacing energy for which HECO currently charges $0.28/kWh with renewable energy that costs $0.088/kWh (grid-tie in costs not included). Residential and commercial systems smaller than 100 kW are able to take advantage of net metering (Energy.gov, 2014); however, utility-scale systems (>2 MW) do not qualify. CNRH has special legal status as a federal entity to avoid certain aspects of state legislation; therefore, CNRH could legally pursue a micro-grid with utility-scale electrical-storage capacity supplied by 100% renewable energy. However, such efforts are unlikely to be well received by the Navy in their effort to privatize existing naval utility infrastructure or by Hawaiians who would pay significantly higher utility rates due to lost economies of scale.

Table 19. NPV of 50 MW Solar PV at $3.10 W(dc)

	$0.28/ kWh	$0.19/ kWh	$0.133/ kWh
NPV (30 yrs)	$ 741,281,914	$ 417,400,685	$ 212,772,574
NPV (12 yrs)	$ 168,492,149	$ 56,625,766	$ (13,726,276)
NPV (10 yrs)	$ 110,387,825	$ 18,780,783	$ (38,740,343)
Total Discounted Cost (30 yrs)	$(235,994,441)	$ (235,994,441)	$ (235,994,441)
kwh produced (30 yrs)	2,690,675,853	2,690,675,853	2,690,675,853
LCOE($/kWh)	0.088	0.088	0.088

Appendix A displays calculation of the NPV on a 30-year timeframe with two scheduled refurbishments conducted at years fifteen and seventeen. The refurbishments are a component of the original cost and reflected as consistent over each scenario.

D. SOLAR-PV BREAK-EVEN ANALYSIS

The solar-PV payback is relatively short and varies depending on payback rate. The payback period is six, nine, and thirteen years, based on a payback rate of $0.28/ kWh, $0.19/kWh, and $0.133/kWh respectively. Figure 8 excludes grid tie-in costs, which will increase the payback period, but even if these connection costs exceeded $100 million, the project would still yield a positive NPV. The dip in the curves at years fifteen and seventeen represent infrastructure upgrades to enable the system to operate effectively for 30 years. Further discussion is found in Chapter III, Section B.

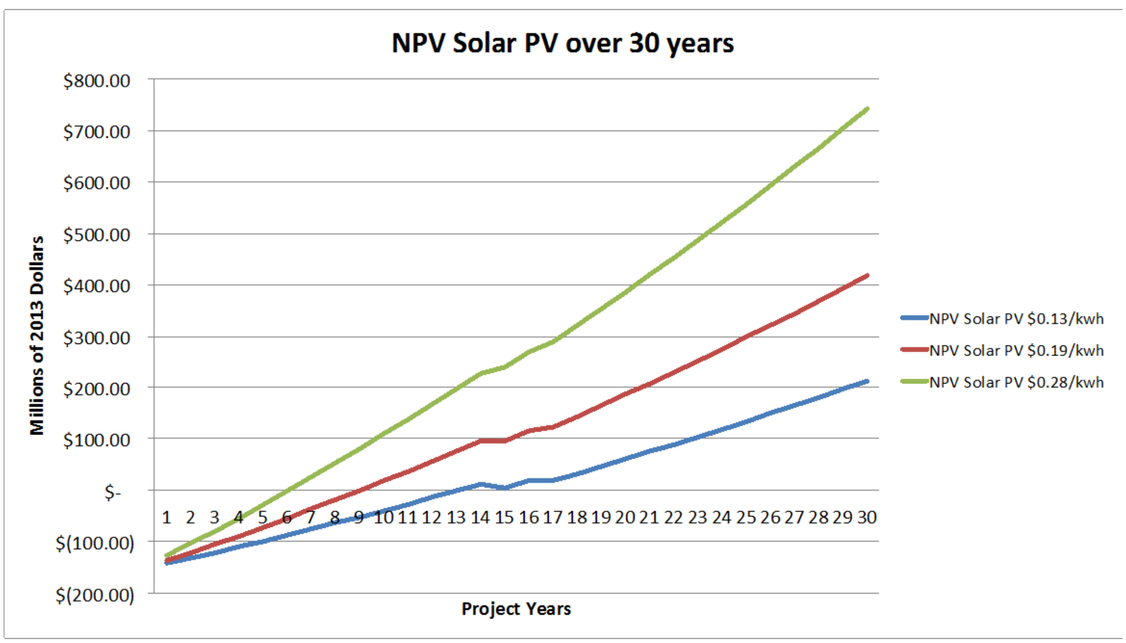

Figure 8. Solar PV Discounted Cash Flow over 30 Years

The payback rates for solar PV will likely not conform to any of the curves in Figure 8, but will blend the three. To find the most likely break-even point, the following analysis was conducted: NAVFAC Hawaii used 717,485 MWH of electricity in FY2013 and Joint Base Pearl Harbor Hickam (JBPHH) consumed 12,061 MWH. The utility costs

for the ships were not included in the JBPHH power-consumption figure, despite their being moored at JBPHH, but the utility costs for the ships were included in the NAVFAC Hawaii calculation. Thus, the JBPHH utility costs are artificially low, because they exclude the electrical consumption of the ships. This report analyzes the maximal percentage of JBPHH utility costs that could be displaced with 50 MW of solar PV at West Loch using 12,061 MWH as a JBPHH consumption rate.

Figure 8 shows that a 50-MW solar PV will produce 96,360 MWH in the first year. JBPHH FY2013 energy consumption was 12,061 MWH. 50 MW of solar PV is projected to produce 84,299 MWH more electricity per year, or 230 MWH more electricity per day, than does JBPHH. However, 50 MW of solar PV cannot entirely replace JBPHH energy requirements. The efficiency or utilization of the panels is 0.22; therefore, only 2,653 MWH (22% of 12,061 MWH/year) would be replaced by solar PV, provided that energy demand remain constant over the day. 2,653 MWH is 2% of the expected yearly output of 50-MW solar PV at West Loch. Additionally, if all JBPHH demand occurred during peak solar producing hours, the maximum replacement percentage would be no more than 13% of the total electrical production of 50 MW.

Table 20 depicts four scenarios:

- Scenario 1: all electricity is sold back to the utility company at a rate of \$0.19.
- Scenario 2: 2% of the electricity is used to displace electricity costs for JBPHH at the rate of \$0.28/kWh, and 98% of the electricity is sold back to the utility company at \$0.19/kWh.
- Scenarios 3 and 4 are identical to scenarios 1 and 3 except that the sell-back rate to the utility was calculated at \$0.133/ kWh rather than \$0.19/ kWh. The savings as a result of the displaced costs are negligible in relation to the \$155 million initial capital investment projected in Figure 8.
-

Table 20. Projected Savings from Supply Power to JBPHH with Solar PV

	$0.28/ kWh	$0.19/ kWh	$0.133/ kWh	MWH Produced by 50 MW PV annually	Total Cost (Dollars)	Difference from Base Case Scenario
Scenario 1		100%		96,360.00	$ 18,308,400	$ -
Scenario 2	2%	98%		96,360.00	$ 18,481,848	$ 173,448
Scenario 3			100%	96,360.00	$ 12,815,880	
Scenario 4	2%		98%	96,360.00	$ 13,099,178	$ 283,298

The projected payback period in years in Figure 8 is six, nine, and thirteen for the $0.28/ kWh, $0.19/ kWh, and $0.133/ kWh scenarios. A hybrid approach can be taken to estimate the change in years of payback using interpolation, with break-even points as follows:

- Scenario 1: nine years to break even (see Figure 8)
- Scenario 2: (six years to break even at $0.28/kWh)*0.02 + (nine years to break even at $0.19/kWh)*0.98= 8.94 years
- Scenario 3: thirteen years to break even (from Figure 8)
- Scenario 4: (six years to break even at $0.28/ kWh)*0.02+ (thirteen years to break even at $0.133/ kWh)*0.98= 12.86 years

Analysis reveals that much higher quantities would need to be replaced at $0.28/ kWh to have any effect in reducing the number of years to break even.

The West Loch solar-PV system will assist NAVFAC in meeting the provisions of National Defense Act of 2010: Section 2842, which requires DOD facilities to use 25% renewable energy in their total consumption (Environmental and Energy Study Institute, 2011). The West Loch solar PV will enable NAVFAC Hawaii to achieve nearly half their goal, assuming that energy consumption does not increase. Ultimately, NAVFAC will need to achieve 179,371 MWH of renewable energy per year by 2025 if electricity usage remains constant for NAVFAC.

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V. DATA ANALYSIS OF LNG

A. MEETING THE HAWAII CLEAN ENERGY INITIATIVE BY 2030

The Hawaii Clean Energy Initiative (HCEI) is an aggressive plan to reduce harmful air pollutants while saving ratepayers money. Table 21 shows the maximum amount of LNG that HECO could use for generating electricity while still complying with the HCEI. The precise number established in this report’s calculation is 0.37 mtpa; however, the number can vary slightly depending on HECO’s efficiency in converting mmBtu of LNG to kW.

The conversion ratio for this research was obtained from the average operating heat rate in 2012 for LNG obtained from the EIA website, which was 8,039 Btu/kWh (EIA, 2014). The conversion was taken as the average between all U.S. utility power producers, both public and private. The average operating heat rate has decreased from 9,533 Btu/kWh in 2002, which equates to a greater than 15% increase in efficiency (EIA, 2014). This report’s interpretation of the HCEI is based on kWh produced, not on Btu of petroleum consumed. The more inefficient the HECO power plants, the more petroleum can be consumed and still meet HCEI specifications. Table 21 illustrates that importing 0.40 mpta of LNG to Oahu would allow HECO to meet the HCEI standard, assuming that LNG is the only source of petroleum for producing electrical power.

Table 21. HCEI Specifics (after HECO, 2014b) (after DBEDT, 2014)

Metric	Quantity	Units
Energy Sent to the System in 2008	7,555,961,805.00	kwh
30% Reduction	5,289,173,263.50	kwh
Electricity Sent to the System 2013	7,187,329,212.00	kwh
Electricity Produced in 2013 by Fossil Fuels	4,174,802,993.00	kwh
2013 Net Revenue	2,116,214,270.00	$
2030 Understood Energy Consumption	5,289,173,263.50	kwh
2030 Understood RE Transmission	3,022,384,722.00	kwh
2030 Understood Non RE Transmission	2,266,788,541.50	kwh
2030 Understood Non RE Transmission	18,22,713.09	mmBTU
2030 Understood Non RE Transmission	0.37	mtpa

B. FGE REPORT NET PRESENT VALUE

Figure 9 shows the discounted cash flow from the savings projected by the FGE report (FGE, 2012), based on cheaper projected costs of LS diesel fuel (FGE, 2012). The FGE report projected prices of delivered LNG and delivered LS diesel costs from 2015–2030 (FGE, 2013).

The total NPV shown in Table 22 amounts to $2.3 billion, which would result in considerable savings in electricity costs. The negative slope in Figure 9 stems from a reduction in LNG from 0.65 mtpa in year 2020 to 0.40 mtpa in 2030 (FGE, 2012). This report assumes a linear reduction in LNG consumption at the rate of 0.025 mpta per year. The estimated savings are based upon projected LNG and LS diesel costs and could vary considerably as prices fluctuate.

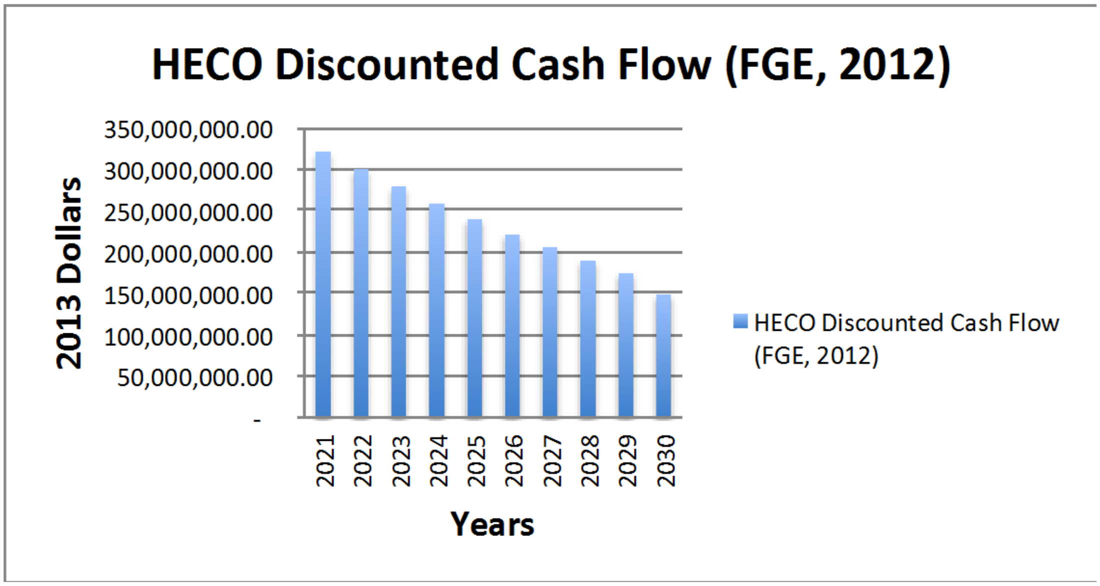

Figure 9. HECO Discounted Cash Flow (after FGE, 2013)

Table 22. FGE LNG NPV (after FGE, 2012)

FGE LNG NPV										
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
All Units in Millions	1	2	3	4	5	6	7	8	9	10
mmBtu	32	31	30	28	27	26	25	23	22	20
Cost of mmBtu in LNG Pricing	436	428	419	409	399	388	374	359	344	313
Cost of mmBtu in LS Diesel	821	797	772	747	721	694	667	639	610	551
Cash Flow	385	369	353	337	322	306	293	279	266	238
Discounted Cash Flow	377	354	333	312	291	272	255	238	222	195

Table 23. FGE NPV (in dollars) (after FGE, 2012)

FGE Report NPV (10 Year)	2,336,903,177.59

C. GALWAY REPORT NET PRESENT VALUES

The Galway report attached a document entitled, "Revised Forecasts for LNG Delivered Cost to Hawaii based on the EIA AEO Early Release 2013," February 22, 2013 (Galway, 2013). Table 24 presents the NPV calculation of the 0.525-0.275 mtpa demand scenario of expected costs savings from replacing LS diesel with LNG (Galway, 2013). Sourcing fuel from the west coast of the United States provides the greatest savings (Galway, 2013)

Table 24. Galway Report NPV 0.525-0.275 mtpa (after Galway, 2013)

Duration	Source	NPV	
20 yr	NPV GoM	$	6,100,776,492.75
20 yr	NPV Jordan Cove	$	6,662,768,020.24
20 yr	NPV Canada	$	1,828,130,401.92
10 yr	NPV GoM	$	4,236,917,688.26
10 yr	NPV Jordan Cove	$	4,451,462,582.14
10 yr	NPV Canada	$	1,755,427,894.84

Table 25 shows that the NPV values increase by greater than 30% as a result of higher quantities of LNG being imported. The findings in tables 24 and 25 are similar because the west coast of the United States, represented by Jordan Cove, yields a higher NPV in both lower and higher quantities of LNG. Additionally, the 20-year NPV in both scenarios is higher than the ten-year NPV.

Table 25. Galway Report NPV 0.65-0.4 mtpa (after Galway, 2013)

Duration	Source	NPV	
20 yr	NPV GoM	$	8,708,378,345.37
20 yr	NPV Jordan Cove	$	9,004,894,101.54
10 yr	NPV Cost GoM	$	5,490,877,424.98
10 yr	NPV Jordan Cove	$	5,659,364,937.50

Table 26 displays the discounted expected costs of the 0.65-0.4 mtpa scenario that can be used to find the LCOE. This can be compared to other energy opportunities besides LS diesel, which is extremely expensive relative to LNG, coal, and solar PV. Table 27 displays the discounted expected costs of the 0.525-0.275 mtpa scenario that can be used to find the LCOE.

Table 26. Galway Report NPV 0.65-0.4 mtpa (after Galway, 2013)

Duration	Source	Total Cost Discounted (2%)	
20 yr	Total Cost GoM	$	6,569,313,446.62
20 yr	Total Cost Jordan Cove	$	6,007,321,919.13
20 yr	Total Cost Canada	$	10,841,959,537.45
10 yr	Total Cost GoM	$	3,831,048,905.91
10 yr	Total Cost Jordan Cove	$	3,616,504,012.03
10 yr	Total Cost Canada	$	6,312,538,699.33

Table 27. Calculations from the Galway Report to Calculated total Costs 0.525-0.275mpta (after Galway, 2013)

Duration	Source	Total Cost Discounted (2%)	
20 yr	Total Cost GoM	$	6,569,313,446.62
20 yr	Total Cost Jordan Cove	$	6,007,321,919.13
20 yr	Total Cost Canada	$	10,841,959,537.45
10 yr	Total Cost GoM	$	3,831,048,905.91
10 yr	Total Cost Jordan Cove	$	3,616,504,012.03
10 yr	Total Cost Canada	$	6,312,538,699.33

formula provided by EIA that averages the efficiency rate for all utility power producers, whether public or private (EIA, 2014). The total cost of LNG, regasification, and transportation costs are factored and included within the "total cost discounted" in tables 26 and 27.

A low estimate results, for several reasons. HECO is operating very old generators, which are likely less efficient than the national average (Galway, 2013). In addition, "total cost discounted" is merely an analysis of the variable cost to put fuel into generators, without including the cost of operating and maintaining facilities (Galway, 2013). Table 28 shows that the LCOE is significantly higher than the solar LCOE, which does not include costs for grid-connection tie-in or the additional infrastructure needed to stabilize the grid against rapid fluctuations due to variable generation (HSIS, 2012).

A comparison of tables 28 and 29 shows that shorter duration assessments have lower LCOEs. The first reason for LCOE is that LNG prices are projected in the Galway report to rise faster than the 2% inflation calculated for the NPV (Galway, 2013). Additionally, the demand for LNG in Table 29 over the first ten years is 0.525 MTPA and the demand over the second ten years dwindles to 0.275 MTPA in this scenario. This negatively impacts economies of scale (Galway, 2013). Table 30 shows the LCOE for solar PV as point of comparison to different LNG LCOE.

Table 28. 0.65-0.40 MPTA Levelized Cost of Energy Calculated from Galway Report Table 4 (N-129) (after Galway, 2013)

0.65-0.40 MTPA

Time	Source	Pwr Generated (kWh)	Total Cost Disc(2%)	LCOE Disc (2%)	Assumptions
20 yr	Gulf of Mexico	62,805,506,327	$ 8,074,108,688	$ 0.129	The LCOE reflects the costs to purchase, ship to HI, and regas LNG.
20 yr	Jordan Cove	62,805,506,327	$ 7,777,592,932	$ 0.124	
10 yr	Gulf of Mexico	38,296,040,443	$ 4,597,612,015	$ 0.120	
10 yr	Jordan Cove	38,296,040,443	$ 4,429,124,503	$ 0.116	

Table 29. 0.525-0.275 Levelized Cost of Energy Calculated from Galway Report Table 5 (after Galway, 2013)

0.525-0.275 MTPA

Time	Source	Pwr Generated (kWh)	Total Cost Disc(2%)	LCOE Disc (2%)	Assumptions
20 yr	Gulf of Mexico	47,487,090,150	$ 8,074,108,688	$ 0.129	The LCOE reflects the costs to purchase, ship to HI, and regas LNG.
20 yr	Jordan Cove	47,487,090,150	$ 7,777,592,932	$ 0.124	
20 yr	Canada	47,487,090,150	$ 10,841,959,537	0.2283	
10 yr	Gulf of Mexico	30,636,832,355	$ 4,597,612,015	$ 0.120	
10 yr	Jordan Cove	30,636,832,355	$ 4,429,124,503	$ 0.116	
10 yr	Canada	30,636,832,355	$ 6,312,538,699	0.2060	

Table 30. Levelized Cost of Energy for 50 MW solar PV (See Table 19 and Appendix A)

Time	Source	Pwr Generated (kWh)	Total Cost Disc(2%)	LCOE Disc (2%)
30yr	solar PV	2,690,675,853	$ 235,994,441	$ 0.088

The best way to compare these costs based on current rates is through the avoided energy costs published by HECO to reimburse renewable energy. The peak avoided energy costs have varied considerably, but from 01JUL13 to 01JUL14, the rate fluctuated from $0.19/ kWh to $0.23/ kWh (HECO, 2014a). This reimbursement rate reflects the variable costs of electrical generation and provides the best comparison to LCOE for LNG and solar PV, though it includes additional costs not found in either.

D. LNG FAIR MARKET PORT COMPARABLE

One variable that this research evaluated was the costs of different port leases in the United States, particularly in the LNG sector. The data for these leases was difficult to find and largely came from local newspapers and interest groups. Despite the irregularity of the data, Table 31 is useful for reference. The numbers in red are lease costs during the construction phase, which will change once the terminals are complete—thus the red numbers are artificially low. A regression analysis was applied under various criteria, but none of the approaches resulted in findings of significance.

Table 31. Comparative Analysis of Port Leases

Location	Company	Date	Acres	Yr. Cap. (mtpa)	Duration (yrs)	Cost (Mil/Yr)	$ 2014 ***	Facility Cost (Mil)	Prop. Taxes (Mil)
Port of Tacoma, WA	Puget Sound Energy	2014	30	0.14	25	2.549	2.549	$275	
Port of Lake Charles, LA	Magnolia LNG	2013	120	8	70	0.672	0.684	3500	0*
Warrenton/ Astoria, OR	Oregon LNG	2013	100	9	65	0.038	0.0387	6500	60
Freeport, TX	Freeport LNG	2012	170	14.7	30	0.5	0.51	10000	5.97
Corpus Christi, TX	Cheniere	2013	110	13.5	7	0.6	0.61	10000	2.5**
WA Port of Vancouver (Oil Terminal)	Tesoro & Savage	2014		12	10	4.5	4.5	100	

Lease Cost in Red are temporary costs until the LNG PORT is built.
* Contract is written so that Magnolia LNG will pay taxes if local legislation changes.
** Cheniere sought legislation to prepay taxes while the plant is being built.
*** From DoD Milcon Inflation Calculator

An interesting facet of this analysis is the relationship between lease costs and property taxes. Oregon LNG proudly posts on its website that its will pay $60 million a year in property taxes for a proposed project in Warrenton, Oregon. Most interesting is that Oregon LNG has a land lease of only $38,000 a year (Sickinger, 2010). While certainly not a direct relationship compared to other petroleum terminals, Warrenton seems to be an example where an extremely low lease was offered in exchange for extremely high property taxes. Therefore, a certain lease premium might be expected if the tenant will not be responsible for property taxes.

E. PROJECTED SAVINGS IN ENERGY COSTS FROM ANNUAL FINANCIAL STATEMENTS

Tables 32 and 33 explain why HECO’s utility-cost-reduction projections are excessively high, based on its 2013 financial statements, and will cost CNRH $15.6 million per year. Table 32 presents an analysis of how fuel costs correspond to HECO’s operating and maintenance cost and total operating costs. The analysis was conducted from HECO’s 2013 annual financial statement, submitted to the PUC in 2013. The report shows that fuel costs constitute 50% of total operating and maintenance (O&M) expenses and 41% of total operating expense (HECO, 2014b).

Table 32. Analysis of Fuel Costs from HECO 2013 Financial Statements (after HECO, 2014b)

Metric	Amount	Percentage
Total Cost of Fuel Consumed in 2013	$ 827,800,958.00	
Maintence Expense	$ 76,521,565.00	
Operating Expense	$ 1,582,892,531.00	
Total Operating Expense	$ 2,007,528,107.00	
Fuel Consumed/ Operating & Maintenance Expense		49.89%
Fuel Consumed/ Total Operating Expesne		41.23%

The FGE and Galway reports projected that replacing LS diesel with LNG would directly reduce fuel costs by 25%–50% (FGE, 2012) (Galway, 2013). Over the range of expected savings in Table 33, O&M expenses are likely to decrease 17%–30%. However, total operating expenses only decrease by 10%–21%. Since utility rates are no longer coupled to the amount of electricity sold in Hawaii, the rates are established based on the expected operating expense produced by HECO and approved by the PUC. The difference between the O&M expense and total operating expense is approximately 8%, or $15.6 million per year to CNRH.

Table 33. Fuel Savings Translated Percent Savings for HECO (after HECO, 2014b)

% Savings: Cost (LNG Savings/Diesel)	25%	30%	35%	40%	45%	50%
Savings from LNG Consumed	207	248	290	331	373	414
O&M Expense minus LNG Savings	1376	1335	1293	1252	1210	1169
Total Operating Expense- LNG Savings	1801	1759	1718	1676	1635	1594

% Change in O&M Expense	17%	20%	22%	25%	27%	30%
% Change in Total Operating Expense	10%	12%	14%	16%	19%	21%

Numbers from the 2013 Annual Finacial Statement (HECO, 2013)

F. IMPACT OF AN LNG TERMINAL ON THE RENEWABLE ENERGY MARKET

Utility-scale independent power producers (IPP) are reimbursed on a contracted price that is negotiated with the utility company (HECO) at a rate of no less than the published avoided energy rate to HECO. Presently, the avoided energy rate is based on oil prices and was priced at $ 0.19/kWh for peak hours on July 1, 2014 (HECO, 2014a).

According to Table 33 a 50% reduction in fuel costs would result in a 30% reduction in avoided energy costs. The reduction in avoided energy costs is associated with operating and maintenance costs and not total operating costs; therefore, avoided energy costs are affected more by changes in fuel costs than overall utility costs. Table 33 shows that a 50% reduction in fuel costs would result in a maximum 21% reduction in utility rates and at least a 30% reduction in avoided energy costs. A 30% reduction in avoided energy costs would lower the peak payback rate from $0.19/kWh to $0.133/kWh.

Figure 7 shows that a 30% reduction in the payback rate would have a $200 million reduction in NPV over the 30-year life of 50-MW solar PV. The $200 million reduction spread over 30 years results in a reduction of $6.67 million per year in NPV from avoided energy costs, as seen in Table 34.

Table 34. Avoided Energy Costs (after HECO, 2014a)

Metric	$/kwh
Avoided Energy Costs 2014	**0.19**
Avoided Energy Cost with 30% Savings LNG	**0.133**

G. VALUE OF CARGO PORT TERMINAL

The Navy would have to forgo other potential income opportunities to pursue the LNG-import terminal. If the Navy plans to lease land for an LNG terminal to reduce costs, it should also consider other potentially lucrative options for leasing the land. Lost

opportunity costs must be considered to determine the value of an LNG-import terminal land lease.

This report claims no specialty in valuing commercial property leases, but notes that the Port Authority of New York and New Jersey has leases that vary in cost from $40,000 to 80,000 per acre (The Port Authority of New York and New Jersey, 2000) (The Port Authority of New York and New Jersey, 2011).

The Navy could potentially use the land designated for an LNG terminal and instead lease the land as a container port. If the Navy leased 100 acres of land at a rate of $60,000 per acre per year, the lease would be worth $6 million a year. Therefore, $6 million is the opportunity cost that this report will use in considering negotiating leverage for the Navy.

H. COST OF REMOVAL OF HOUSES FROM THE BLAST ZONE

The area in the vicinity of Pearl City includes military housing that might fall within a significant accident-potential zone (APZ), in accordance with reference SANDIA 2004–6258. In the event that risk accident could not be mitigated, approximately 200 government-owned housing units would need to be relocated. The cost of relocating the residents was assessed at an average basic allowance housing (BAH) for an E-7 with dependents in Pearl Harbor, which equates to $2,835 a month (NS Pearl Harbor, 2014).

200 (homes)*12 months/year*$2,835 BAH/ month= $6,804,000.00

The sailors would receive BAH regardless of the scenario, yet the privatized company with the housing contract would likely need to be reimbursed for approximately $6.8 million per year.

I. HECO'S BEST LNG IMPORT TERMINAL ALTERNATIVE

The ZOPA process began in this project with determining the potential cumulative value of an LNG project. Even the least attractive project for HECO has a NPV in excess of $1.7 billion over ten years (Table 25). Therefore, this research concludes that pursuing LNG, compared with the current path is extremely beneficial.

The next step in the ZOPA process is comparing alternative ports for HECO. The goal is to analyze the difference in average annual costs among different re-gas options. The analysis in Table 35 takes into consideration LNG purchase costs, re-gas costs, and transportation costs (Galway, 2013). The data was taken from a range of delivered quantities from 0.85 mtpa to 0.28 mtpa (Galway, 2013).

Table 35. Average Annual Cost for HECO on Competing Terminals (after Galway, 2013)

Sites	average annual cost	Issues
Onshore LNG Terminal	195	Most expensive
ATB Regas Barges / OFFSHORE shuttle	165	Unproven
Small Scale Onshore	149	Site/timescale issues
2 x FSRU - OFFSHORE Double Buoy	147	Unproven technology
Pearl Harbor Dockside Small/Mid FSRU	129	Second best
Pearl Harbor Dockside Fullsize FSRU	100	Best option

Conclusion: $50M gap (per year) between Pearl Harbor and next best option (small scale onshore)

Figure 10 is the visual depiction of Table 35 with the exception of breaking each site option savings into various demand scenarios. The numerical computations can be found in Appendix B.

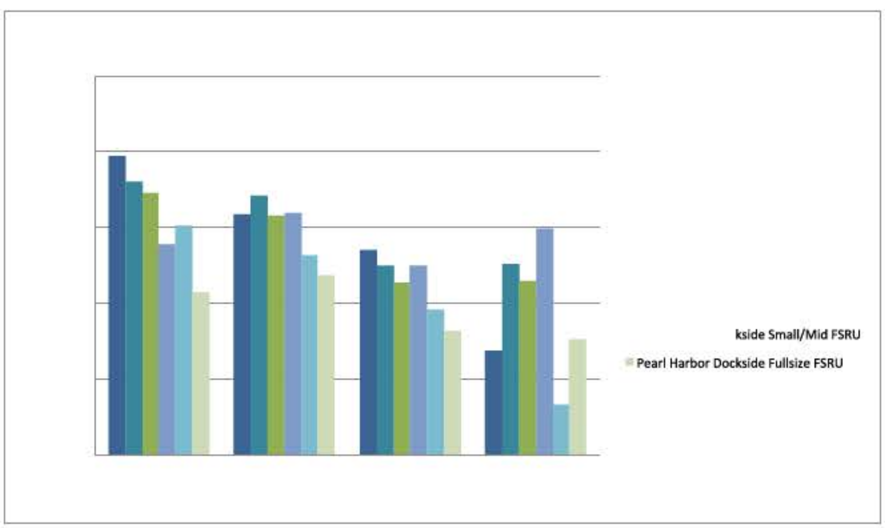

Figure 10. Total Re-gas and Transportation Costs for LNG per Year over Various Quantities of Shipment (after Galway, 2013)

The Pearl Harbor dockside, full-size FSRU is approximately $50 million less expensive, on average, than different shipment quantities from 0.85, 0.65, 0.53, 0.55, 0.40, and 0.28 mtpa (Galway, 2013). The Pearl Harbor FSRU is less expensive at every consumption level, with the exception of shipments of 0.28 mtpa. Providing that all non-renewable electricity produced in Hawaii comes from LNG, HECO can use approximately 0.40 mtpa and still meet HCEI requirements.

This table suggests that if an equal probability of shipment exists over the stated range of analysis, HECO would pay no more than $50 million a year more for the Pearl Harbor option than for the next least-expensive option, which is the 2 x FSRU–double buoy offshore option.

J. ZONE OF POSSIBLE AGREEMENT FOR AN LNG-IMPORT TERMINAL

The LNG-import terminal is a commonly beneficial project for both CNRH and HECO. Table 36 shows that HECO would benefit by $50 million a year in using Pearl Harbor over the least expensive alternative. CNRH benefits from lower utility costs of 20%, according to the overlap from HECO's and this study's estimates (CNRH, 2014b). A 20% reduction in FY2013 CNRH utility costs of $195 million would result in savings of $39 million per year. CNRH would likely pay the cost of $6.8 million per year to subsidize privatized military housing away from the blast area.

Table 36. Zone of Possible Agreement

	HECO	CNRH
Benefits	**Least Expensive Alternative: $50 mil/ yr**	**20% Reduction in Utility Costs: $39 mil/yr**
Costs		**Home relocation: $6.8 mil/ year**
Value	**$50 mil/year**	**($32.2) million/year**

The ZOPA process shows that CNRH should expect to be paid by HECO within a range from $50 million per year to negative $32.2 million per year. At any point on the

scale, both parties are better off than they would have been if they had chosen not to trade. ZOPA theory suggests that both sides will migrate toward the middle of the ZOPA before reaching a deal (Spangler, 2013). Applying ZOPA logic to this negotiation, the lease would be valued at $8.9 million per year.

Ultimatum theory also applies to this negotiation because both parties are able to benefit from the deal and both parties have to consent to the deal. The theory is principled on fairness. The party who stands to benefit least will often not consent to a deal unless a payout of 20% or greater is received (Thaler and Mullainathan, 2008).

HECO's least-lucrative LNG scenario has an NPV of $1.7 billion over ten years; therefore, HECO stands to benefit in inflation-adjusted dollars by $170 million per year. The logic of ultimatum theory states that CNRH will not agree to a deal unless it receives compensation of no less than 20% of $170 million per year, which would be $34 million per year. A lease of $34 million a year is well within the ZOPA window.

VI. CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations of this study should be admitted as key in any discussion of the proposed projects. In particular the data analyzed from the FGE report and the Galway report when compared to HECO's 2013 financial statements revealed that a 20–30% reduction in utility costs as a result of LNG is unlikely.

This research presents a framework of some of the costs and benefits of building solar PV and LNG infrastructure on JBPHH. This report found that both projects are beneficial to CNRH providing that the analyzed assumptions are realistic. A high degree of uncertainty can be placed on the NPV of the solar-PV project and the LNG terminal, which are largely dependent on the differential between the cost of LNG and LS diesel from 2020–2030. While this report analyzed the best information available, fluctuations in expected costs can drastically change the benefits of projects.

The findings in this study can be used for further analysis regarding the PUC's willingness to approve an LNG-import terminal and the expected disposal costs of an LNG-import terminal.

A. CONCLUSIONS

The major conclusions of this study are as follows:

(1) Potential Reductions in Utility Rates Have Been Overstated

Hawaii Electric Company has overstated projected reductions in utility rates from a transition to liquid natural gas. HECO has communicated to CNRH that it expects utility costs to drop by 20–30% if an LNG-import terminal is built (CNRH, 2013). This level of reduction is unlikely, because even a 50% reduction in fuel cost (the maximum fuel savings projected by the FGE and Galway reports) would result in only a 21% reduction in HECO's 2013 total operating expense (See Table 33). This report estimates a 10%–21% reduction in the utility rate as the maximum possible, assuming HECO maintains the same operating margins.

(2) Further Research is Needed to Determine Whether LNG Will Reduce Rates More than Renewable Energy

The average annual rate to produce electricity with solar photovoltaic is projected to be $0.088/kWh. The average annual rate to deliver LNG to Hawaii was calculated as $0.10-$0.18/kWh. However, these rates do not directly translate into utility rates. The solar-PV average annual rate does not take into consideration grid tie-in costs, advanced smart-grid technology, or required utility-scale storage to accommodate fluctuations in current under dynamic weather conditions. The LNG average annual rate does not consider the costs of transportation from an import site to a power plant, operating the power plants, modernization, or any other costs. While replacing LS diesel with LNG will almost certainly result in savings, further research is required to determine if LNG will reduce utility rates significantly more than renewable energy such as solar PV.

(3) An LNG-Import Terminal is Expected to Benefit All Parties

Building an LNG-import terminal in Pearl Harbor presents a winning situation for both CNRH and HECO. CNRH benefits by $32.2 million per year in electrical cost savings (Table 36), and HECO benefits by $170–$460 million per year on average, based on the projected NPV (tables 23 and 24). The benefits of building an LNG-import terminal are much greater than either party's alternative.

(4) HECO's Best Alternative LNG Site is Significantly More Expensive

HECO's best alternative for a LNG site is $50 million more expensive than Pearl Harbor (Table 35). CNRH will likely benefit from $32.2 million per year from reduced utility costs from an LNG terminal. ZOPA theory suggests the most likely lease agreement would be at the midpoint between acceptable terms. The midpoint between HECO and CNRH is $8.9 million per year.

(5) Ultimatum Theory

Ultimatum theory suggests that in the event that both parties stand to gain from a zero-sum transaction, the party with the lessor terms will not agree to the deal without a payout of 20% or greater (Thaler and Mullainathan, 2008). This perspective places the

lease rate at no less than 20% of HECO's economic benefit of $170 million per year—that is, at $34 million per year.

(6) Benefits of Solar PV

Solar PV is a very attractive project because of a $280-800 million NPV for a 50-MW system at West Loch, as shown in Figure 7. However, the NPV does not include grid tie-in costs, required smart-grid costs, or energy-storage costs to compensate for fluctuations in current. This study found that CNRH could invest a maximum of $280-$800 million in the excluded costs and still have a positive NPV. The project's cost savings are largely dependent upon whether the generated renewable energy can displace the current utility rate of $0.28/ kWh or will be reimbursed at much lower rate by the utility company.

(7) Indirect Impact of an LNG terminal

Building an LNG terminal will reduce the rate at which the utility company reimburses renewable energy. A 30% reduction in the utility payback rate results in a $200 million NPV loss for a 50-MW solar-PV system over 30 years (Figure 7). The 30% reduction in the renewable-energy payback rate is consistent with Table 33. The renewable-energy payback rate is determined by avoided energy costs (a component of operating and maintenance costs), and utility rates are determined by total operating costs. This means the yearly cash flow paid by the utility for energy from solar PV could be 30% less. The only way to avoid drastic reductions in payback rates is to enter into a long-term contract with HECO.

B. RECOMMENDATIONS

To secure best outcomes for Navy negotiations, the following recommendations are made:

(1) Commission a Special Report for Legal and Environmental Issues

The 50-MW solar-PV project and the LNG-import terminal are potentially worth hundreds of millions of dollars to CNRH and billions of dollars to HECO over the next decade. This study strongly recommends commissioning a professional report on legal

and environmental issues, including data on commercial port leases that is not publically available. HECO should be engaged to determine their initial bargaining position.

(2) Investigate the Benefits of a JBPHH Electrical Island

CNRH should pursue a 50-MW solar-PV system at West Loch. Further research is needed on the ability to displace energy costs of $0.28/ kWh. This report found that an $800-million initial investment for grid tie-in costs, smart-grid infrastructure, and energy-storage would yield a positive NPV. Further research to investigate the economics of smart-grid infrastructure and electrical-energy storage is advised.

(3) Build a BESS

CNRH should investigate partnering with HECO to build a 2MW battery energy-storage system (BESS) (Shimogawa, 2014). A BESS would be best used in close proximity to large renewable-energy generation systems. A BESS would benefit HECO by preventing large fluctuations in voltage, which degrade grid security, and also provide emergency power if installed in conjunction with a smart grid. CNRH could potentially use the BESS to power critical infrastructure during blackouts that coincide with national-security threats requiring immediate military response.

(4) Commission a LNG-Import Terminal Disposal Report

The disposal costs of an LNG-Import terminal could be expensive. The magnitude of the costs should be analyzed before proceeding with the project because they significantly impact the NPV.

APPENDIX A. 50-MW SOLAR-PV NPV

The following tables have been included to show the assumptions that were used in this research. Table 37 shows the solar-PV assumptions that were used in calculating the solar-PV NPV in Tables 38, 39, and 40.

Table 37. Assumptions for 50MW Solar PV NPV

Savings per kWh	$0.28	$0.19	$0.13
System Capacity (kW)	50000	50000	50000
Efficiency / Usage	22%	22%	22%
kWh/day	264,000	264,000	264,000
kWh / year	96,360,000	96,360,000	96,360,000
$/kWh electricity cost avoided	0.28	0.19	0.133
Electricity price increase (yr)	2%	2%	2%
Avoided electricity cost (yr)	$ 269,808	$ 183,084	$ 128,159
System Cost ($3.10/W)	$ 155,000,000	$ 155,000,000	$ 155,000,000
Annual maintenance cost	$ 2,000,000	$ 2,000,000	$ 2,000,000
Discount rate	1.90%	1.90%	1.90%
Inflation rate	2%	2%	2%
Maintenance cost per kW	$ 40.00	$ 40.00	$ 40.00
Output degradation per year	0.5%	0.5%	0.5%

Table 38. 50 MW Solar PV NPV with $0.28 kWh payback

Years	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Year in project	1	2	3	4	5	6	7	8	9	10	11	12	13	14
cost savings														
PV generation / kW	96,360,000	95,878,200	95,398,809	94,921,815	94,447,206	93,974,970	93,505,095	93,037,570	92,572,382	92,109,520	91,648,972	91,190,727	90,734,774	90,281,100
electricity cost	0.28	0.2856	0.291312	0.29713824	0.303081005	0.309142625	0.315325477	0.321631987	0.328064627	0.334625919	0.341318438	0.348144806	0.355107702	0.362209857
avoided electricity cost	$ 26,980,800	$ 27,382,814	$ 27,790,818	$28,204,901	$ 28,625,154	$29,051,669	$29,484,539	$29,923,858	$30,369,724	$30,822,233	$31,281,484	$31,747,578	$32,220,617	$32,700,704
annual maintenance	$ (2,000,000)	$ (2,040,000)	$ (2,080,800)	$ (2,122,416)	$ (2,164,864)	$ (2,208,162)	$ (2,252,325)	$ (2,297,371)	$ (2,343,319)	$ (2,390,185)	$ (2,437,989)	$ (2,486,749)	$ (2,536,484)	$ (2,587,213)
additional maintenance														
total cost savings	$ 24,980,800	$ 25,342,814	$ 25,710,018	$26,082,485	$ 26,460,290	$26,843,507	$27,232,214	$27,626,487	$28,026,405	$28,432,048	$28,843,495	$29,260,829	$29,684,133	$30,113,491
Investment	$ (155,000,000)													
Discounted Cash Flow	$ (127,129,112)	$ 24,406,554	$ 24,298,520	$24,190,911	$ 26,460,290	$26,843,507	$27,232,214	$27,626,487	$28,026,405	$28,432,048	$28,843,495	$29,260,829	$29,684,133	$30,113,491

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	89,829,694	89,380,546	88,933,643	88,488,975	88,046,530	87,606,297	87,168,266	86,732,425	86,298,762	85,867,269	85,437,932	85,010,743	84,585,689	84,162,760	83,741,947	83,323,237
	0.369454054	0.376843135	0.384379997	0.392067597	0.399908949	0.407907128	0.416065271	0.424386576	0.432874308	0.441531794	0.45036243	0.459369678	0.468557072	0.477928213	0.487486778	0.497236513
	$ 33,187,945	$33,682,445	$ 34,184,314	$34,693,660	$35,210,595	$35,735,233	$36,267,688	$36,808,077	$37,356,517	$37,913,129	$38,478,035	$39,051,357	$39,633,223	$40,223,758	$40,823,092	$41,431,356
	$ (2,638,958)	$ (2,691,737)	$ (2,745,571)	$ (2,800,483)	$ (2,856,492)	$ (2,913,622)	$ (2,971,895)	$ (3,031,333)	$ (3,091,959)	$ (3,153,799)	$ (3,216,874)	$ (3,281,212)	$ (3,346,836)	$ (3,413,773)	$ (3,482,048)	$ (3,551,689)
	$ (20,000,000)		$ (12,500,000)													
	$ 10,548,987	$30,990,708	$ 18,938,742	$31,893,177	$32,354,103	$32,821,611	$33,295,793	$33,776,744	$34,264,558	$34,759,331	$35,261,160	$35,770,146	$36,286,386	$36,809,985	$37,341,043	$37,879,666
	$ 10,548,987	$30,990,708	$ 18,938,742	$31,893,177	$32,354,103	$32,821,611	$33,295,793	$33,776,744	$34,264,558	$34,759,331	$35,261,160	$35,770,146	$36,286,386	$36,809,985	$37,341,043	$37,879,666

Discounted Cash Flow	$ 741,152,514
DCF for 12 years only	$ 168,492,149
DCF for 10 years only	$ 110,387,825
Total Cost over 30 years	$ (235,994,441)
kwh produced (30 yrs)	2,690,675,853
LCOE($/kWh)	0.088

Table 39. 50 MW Solar PV NPV with $0.19 kWh payback

Years	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Year in project	1	2	3	4	5	6	7	8	9	10	11	12	13	14
cost savings														
PV generation / kW	96,360,000	95,878,200	95,398,809	94,921,815	94,447,206	93,974,970	93,505,095	93,037,570	92,572,382	92,109,520	91,648,972	91,190,727	90,734,774	90,281,100
electricity cost	0.19	0.1938	0.197676	0.20162952	0.20566211	0.209775353	0.21397086	0.218250277	0.222615282	0.227067588	0.23160894	0.236241119	0.240965941	0.24578526
avoided electricity cost	$ 18,308,400	$ 18,581,195	$ 18,858,055	$ 19,139,040	$ 19,424,212	$ 19,713,632	$ 20,007,366	$ 20,305,475	$ 20,608,027	$ 20,915,086	$21,226,721	$21,542,999	$21,863,990	$22,189,764
annual maintenance	$ (2,000,000)	$ (2,040,000)	$ (2,080,800)	$ (2,122,416)	$ (2,164,864)	$ (2,208,162)	$ (2,252,325)	$ (2,297,371)	$ (2,343,319)	$ (2,390,185)	$ (2,437,989)	$ (2,486,749)	$ (2,536,484)	$ (2,587,213)
additional maintenance														
total cost savings	$ 16,308,400	$ 16,541,195	$ 16,777,255	$ 17,016,624	$ 17,259,347	$ 17,505,471	$ 17,755,041	$ 18,008,104	$ 18,264,708	$ 18,524,901	$18,788,732	$19,056,251	$19,327,507	$19,602,550
Investment	$ (155,000,000)													
cash flows	$ (136,105,594)	$ 15,930,101	$ 15,856,172	$ 15,782,532	$ 17,259,347	$ 17,505,471	$ 17,755,041	$ 18,008,104	$ 18,264,708	$ 18,524,901	$18,788,732	$19,056,251	$19,327,507	$19,602,550

Years	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Year in project	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
cost savings																
PV generation / kW	89,829,694	89,380,546	88,933,643	88,488,975	88,046,530	87,606,297	87,168,266	86,732,425	86,298,762	85,867,269	85,437,932	85,010,743	84,585,689	84,162,760	83,741,947	83,323,237
electricity cost	0.250700965	0.255714984	0.260829284	0.26604587	0.271366787	0.276794123	0.282330005	0.287976605	0.293736137	0.29961086	0.305603077	0.311715139	0.317949442	0.324308431	0.330794599	0.337410491
avoided electricity cost	$ 22,520,391	$22,855,945	$ 23,196,498	$23,542,126	$23,892,904	$24,248,908	$24,610,217	$ 24,976,909	$25,349,055	$25,726,766	$26,110,095	$26,499,135	$26,893,973	$27,294,693	$ 27,701,384	$ 28,114,134
annual maintenance	$ (2,638,958)	$ (2,691,737)	$ (2,745,571)	$ (2,800,483)	$ (2,856,492)	$ (2,913,622)	$ (2,971,895)	$ (3,031,333)	$ (3,091,959)	$ (3,153,799)	$ (3,216,874)	$ (3,281,212)	$ (3,346,836)	$ (3,413,773)	$ (3,482,048)	$ (3,551,689)
additional maintenance	$ (20,000,000)		$ (12,500,000)													
total cost savings	$ (118,566)	$20,164,208	$ 7,950,927	$20,741,643	$21,036,411	$21,335,286	$21,638,322	$ 21,945,577	$22,257,106	$22,572,968	$22,893,221	$23,217,923	$23,547,136	$23,880,920	$ 24,219,335	$ 24,562,445
Investment																
cash flows	$ (118,566)	$20,164,208	$ 7,950,927	$20,741,643	$21,036,411	$21,335,286	$21,638,322	$ 21,945,577	$22,257,106	$22,572,968	$22,893,221	$23,217,923	$23,547,136	$23,880,920	$ 24,219,335	$ 24,562,445

Discounted Cash Flow (DCF)	[illegible]
DCF for 12 years only	$ 56,625,766
DCF for 10 years only	$ 18,780,783
Total Cost over 30 years	$(235,994,441)
kwh produced over 30 years	2,690,675,853
LCOE($/kWh)	0.088

Table 40. 50 MW Solar PV NPV with $0.133 payback

Years	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Year in project	1	2	3	4	5	6	7	8	9	10	11	12	13	14
cost savings														
PV generation / kW	96,360,000	95,878,200	95,398,809	94,921,815	94,447,206	93,974,970	93,505,095	93,037,570	92,572,382	92,109,520	91,648,972	91,190,727	90,734,774	90,281,100
electricity cost	0.13	0.13566	0.1383732	0.141140664	0.143963477	0.146842747	0.149779602	0.152775194	0.155830698	0.158947312	0.162126258	0.165368783	0.168676159	0.172049682
avoided electricity cost	$ 12,815,880	$ 13,006,837	$ 13,200,638	$ 13,397,328	$ 13,596,948	$ 13,799,543	$ 14,005,156	$ 14,213,833	$ 14,425,619	$ 14,640,561	$ 14,858,705	$ 15,080,100	$ 15,304,793	$ 15,532,834
annual maintenance	$ (2,000,000)	$ (2,040,000)	$ (2,080,800)	$ (2,122,416)	$ (2,164,864)	$ (2,208,162)	$ (2,252,325)	$ (2,297,371)	$ (2,343,319)	$ (2,390,185)	$ (2,437,989)	$ (2,486,749)	$ (2,536,484)	$ (2,587,213)
additional maintenance														
total cost savings	$ 10,815,880	$ 10,966,837	$ 11,119,838	$ 11,274,912	$ 11,432,084	$ 11,591,381	$ 11,752,831	$ 11,916,461	$ 12,082,300	$ 12,250,375	$ 12,420,716	$ 12,593,351	$ 12,768,309	$ 12,945,621
Investment	$ (155,000,000)													
cash flows	$ (141,294,032)	$ 10,561,680	$ 10,509,352	$ 10,457,224	$ 11,432,084	$ 11,591,381	$ 11,752,831	$ 11,916,461	$ 12,082,300	$ 12,250,375	$ 12,420,716	$ 12,593,351	$ 12,768,309	$ 12,945,621

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
89,829,694	89,380,546	88,933,643	88,488,975	88,046,530	87,606,297	87,168,266	86,732,425	86,298,762	85,867,269	85,437,932	85,010,743	84,585,689	84,162,760	83,741,947	83,323,237
0.175490675	0.179000489	0.182580499	0.186232109	0.189956751	0.193755886	0.197631004	0.201583624	0.205615296	0.209727602	0.213922154	0.218200597	0.222564609	0.227015901	0.231556219	0.236187344
$ 15,764,274	$ 15,999,161	$ 16,237,549	$ 16,479,488	$ 16,725,033	$ 16,974,236	$ 17,227,152	$ 17,483,836	$ 17,744,346	$ 18,008,736	$ 18,277,067	$ 18,549,395	$ 18,825,781	$ 19,106,285	$ 19,390,969	$ 19,679,894
$ (2,638,958)	$ (2,691,737)	$ (2,745,571)	$ (2,800,483)	$ (2,856,492)	$ (2,913,622)	$ (2,971,895)	$ (3,031,333)	$ (3,091,959)	$ (3,153,799)	$ (3,216,874)	$ (3,281,212)	$ (3,346,836)	$ (3,413,773)	$ (3,482,048)	$ (3,551,689)
$ (20,000,000)		$ (12,500,000)													
$ (6,874,684)	$ 13,307,425	$ 991,978	$ 13,679,006	$ 13,868,540	$ 14,060,613	$ 14,255,257	$ 14,452,504	$ 14,652,386	$ 14,854,938	$ 15,060,192	$ 15,268,183	$ 15,478,945	$ 15,692,512	$ 15,908,920	$ 16,128,205
$ (6,874,684)	$ 13,307,425	$ 991,978	$ 13,679,006	$ 13,868,540	$ 14,060,613	$ 14,255,257	$ 14,452,504	$ 14,652,386	$ 14,854,938	$ 15,060,192	$ 15,268,183	$ 15,478,945	$ 15,692,512	$ 15,908,920	$ 16,128,205

Discounted Cash Flow (DCF)	$ 212,772,574
DCF for 12 years only	$ (13,726,276)
DCF for 10 years only	$ (38,740,343)
Total Cost over 30 years	$ (235,994,441)
kwh produced over 30 years	2,690,675,853
LCOE ($/kWh)	0.088

APPENDIX B. LNG CALCULATIONS

Appendix B shows the calculations used for calculating the NPV from the FGE report as well as the NPV from two different Galway report scenarios. This appendix concludes with the numbers used to determine that the Pearl Harbor LNG terminal was \$50 million less expensive than alternative options.

Table 41. FGE LNG NPV (after FGE 2012)

FGE LNG NPV	1	2	3	4	5
mmBtu	32,017,634.35	30,786,186.88	29,554,739.40	28,323,291.93	27,091,844.45
Cost of mmBtu in LNG Pricing	$ 436,080,179.85	$427,866,425.19	$ 418,967,985.73	$ 409,384,861.48	$ 399,117,052.44
Cost of mmBtu in LS Diesel	$ 820,611,968.39	$796,561,799.20	$ 771,910,683.65	$ 746,658,621.73	$ 720,805,613.44
Cash Flow	327,414,428.54	311,578,014.02	295,825,337.91	280,156,400.24	264,571,201.00
Discounted Cash Flow	320,994,537.79	299,479,059.99	278,762,823.04	258,821,208.94	239,630,288.14

FGE Report NPV (10 Year)	2,336,903,177.59

FGE LNG NPV	6	7	8	9	10
mmBtu	25,860,396.98	24,628,949.50	23,397,502.03	22,166,054.55	19,703,159.60
Cost of mmBtu in LNG Pricing	$388,164,558.59	$374,015,227.11	$ 359,432,426.11	$344,416,155.60	$313,083,206.04
Cost of mmBtu in LS Diesel	$694,351,658.78	$666,853,436.66	$ 638,798,600.29	$610,187,149.65	$551,294,405.61
Cash Flow	249,069,740.18	235,720,849.56	222,248,814.18	208,653,634.05	181,093,839.56
Discounted Cash Flow	221,166,801.45	205,209,184.89	189,687,222.91	174,592,027.04	148,560,023.40

Table 42. Galway LNG NPV 0.65 MTPA after Galway 2013 (1 of 3)

		2015	2016	2017	2018	2019	2020	2021	2022
Volume	(mmBtu)	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39
US GoM LNG Supply	**Total Delivered Cost to HI**	**$ 413,027,483.62**	**$ 435,439,827.69**	**$ 441,843,354.57**	**$ 454,650,408.32**	**$ 461,053,935.20**	**$ 467,457,462.08**	**$ 477,062,752.40**	**$ 489,869,806.15**
Jorda Cove LNG Supply	**Total Delivered Cost to HI**	**$ 393,816,902.98**	**$ 416,229,247.06**	**$ 422,632,773.93**	**$ 435,439,827.69**	**$ 445,045,118.01**	**$ 451,448,644.88**	**$ 457,852,171.76**	**$ 477,062,752.40**
LSFO		$ 707,589,720.00	$ 704,387,956.56	$ 733,203,827.51	$ 752,414,408.14	$ 774,826,752.21	$ 794,037,332.85	$ 816,449,676.92	$ 842,063,784.43
ULSD		$ 893,291,999.45	$ 893,291,999.45	$ 925,309,633.84	$ 950,923,741.35	$ 976,537,848.86	$ 1,005,353,719.81	$ 1,030,967,827.33	$ 1,059,783,698.28

Cash Flow GoM (ULSD)	$ 480,264,515.84	$ 457,852,171.76	$ 483,466,279.27	$ 496,273,333.03	$ 515,483,913.66	$ 537,896,257.74	$ 553,905,074.93	$ 569,913,892.12
Cash Flow Jordan Cove (ULSD)	$ 499,475,096.47	$ 477,062,752.40	$ 502,676,859.91	$ 515,483,913.66	$ 531,492,730.86	$ 553,905,074.93	$ 573,115,655.56	$ 582,720,945.88

GoM	Disc (2%) Cash Flow	$ 537,896,257.74	$ 543,044,191.11	$ 547,783,441.10
Jordan Cove	Disc (2%) Cash Flow	$ 553,905,074.93	$ 561,878,093.69	$ 560,093,181.35

GoM	Discted 2% Cost	$ 467,457,462.08	$ 467,708,580.78	$ 470,847,564.54
Jordan Gove	Discted 2% Cost	$ 451,448,644.88	$ 448,874,678.20	$ 458,537,824.29

20 yr	NPV GoM	$	8,708,378,345.37
20 yr	NPV Jordan Cove	$	9,004,894,101.54

10 yr	NPV GoM	$	5,490,877,424.98
10 yr	NPV Jordan Cove	$	5,659,364,937.50

Table 43. Galway LNG NPV 0.65 MTPA after Galway 2013 (2 of 3)

2023	2024	2025	2026	2027	2028	2029	2030	2031
32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	32017634.39	19703159.62	19703159.62
$ 502,676,859.91	**$ 515,483,913.66**	**$ 525,089,203.98**	**$ 537,896,257.74**	**$ 547,501,548.05**	**$ 557,106,838.37**	**$ 595,527,999.64**	**$ 372,389,716.89**	**$ 415,736,668.07**
$ 489,869,806.15	**$ 499,475,096.47**	**$ 509,080,386.79**	**$ 521,887,440.54**	**$ 531,492,730.86**	**$ 544,299,784.61**	**$ 550,703,311.49**	**$ 348,745,925.34**	**$ 398,003,824.40**
$ 867,677,891.94	$ 893,291,999.45	$ 918,906,106.96	$ 944,520,214.48	$ 973,336,085.43	$ 998,950,192.94	$1,027,766,063.89	$ 650,204,267.59	$ 667,937,111.25
$1,091,801,332.66	$1,123,818,967.05	$1,155,836,601.44	$1,191,055,999.27	$1,223,073,633.66	$1,258,293,031.49	$1,290,310,665.88	$ 815,710,808.43	$ 839,354,599.98
$ 589,124,472.76	$ 608,335,053.39	$ 630,747,397.46	$ 653,159,741.54	$ 675,572,085.61	$ 701,186,193.12	$ 694,782,666.24	$ 443,321,091.54	$ 423,617,931.92
$ 601,931,526.51	$ 624,343,870.59	$ 646,756,214.66	$ 669,168,558.73	$ 691,580,902.80	$ 713,993,246.87	$ 739,607,354.39	$ 466,964,883.09	$ 441,350,775.58
$ 555,145,148.51	$ 562,007,556.57	$ 571,287,351.10	$ 579,987,158.48	$ 588,126,155.51	$ 598,455,664.24	$ 581,363,054.61	$ 363,677,703.74	$ 340,700,245.34
$ 567,213,521.30	$ 576,797,229.11	$ 585,787,030.06	$ 594,202,530.01	$ 602,062,794.27	$ 609,386,361.30	$ 618,870,348.46	$ 383,073,847.94	$ 354,962,116.07
$ 473,683,632.15	$ 476,227,455.83	$ 475,589,469.95	$ 477,636,483.45	$ 476,633,045.46	$ 475,485,322.27	$ 498,311,189.67	$ 305,489,271.14	$ 334,361,636.12
$ 461,615,259.36	$ 461,437,783.29	$ 461,089,790.99	$ 463,421,111.92	$ 462,696,406.71	$ 464,554,625.21	$ 460,803,895.82	$ 286,093,126.94	$ 320,099,765.39

Table 44. Galway LNG NPV 0.65 MTPA after Galway 2013 (3 of 3)

2032	2033	2034	2035	2036	2037	2038	2039	2040
19703159.62	**19703159.62**	**19703159.62**	**19703159.62**	**19703159.62**	**19703159.62**	**19703159.62**	**19703159.62**	**19703159.62**
$ 423,617,931.92	**$ 431,499,195.77**	**$ 445,291,407.50**	**$ 461,053,935.20**	**$ 476,816,462.90**	**$ 496,519,622.52**	**$ 518,193,098.11**	**$ 528,044,677.92**	**$ 545,777,521.58**
$ 403,914,772.29	**$ 413,766,352.10**	**$ 427,558,563.84**	**$ 443,321,091.54**	**$ 463,024,251.16**	**$ 478,786,778.86**	**$ 498,489,938.49**	**$ 514,252,466.19**	**$ 528,044,677.92**
$ 687,640,270.88	$ 705,373,114.54	$ 725,076,274.16	$ 744,779,433.79	$ 744,779,433.79	$ 744,779,433.79	$ 744,779,433.79	$ 744,779,433.79	$ 744,779,433.79
$ 862,998,391.53	$ 884,671,867.12	$ 910,285,974.63	$ 933,929,766.18	$ 933,929,766.18	$ 933,929,766.18	$ 933,929,766.18	$ 933,929,766.18	$ 933,929,766.18
$ 439,380,459.62	$ 453,172,671.35	$ 464,994,567.13	$ 472,875,830.98	$ 457,113,303.28	$ 437,410,143.65	$ 415,736,668.07	$ 405,885,088.25	$ 388,152,244.59
$ 459,083,619.24	$ 470,905,515.01	$ 482,727,410.79	$ 490,608,674.64	$ 470,905,515.01	$ 455,142,987.31	$ 435,439,827.69	$ 419,677,299.99	$ 405,885,088.25
$ 346,448,493.89	$ 350,317,214.43	$ 352,407,768.99	$ 351,353,707.87	$ 332,982,272.17	$ 312,381,949.04	$ 291,081,925.66	$ 278,612,009.51	$ 261,215,333.49
$ 361,984,300.79	$ 364,025,279.35	$ 365,847,048.32	$ 364,529,471.92	$ 343,029,151.07	$ 325,046,082.11	$ 304,877,277.59	$ 288,079,407.89	$ 273,149,028.93
$ 334,019,848.37	$ 333,562,912.87	$ 337,475,236.41	$ 342,569,865.17	$ 347,334,956.31	$ 354,595,725.94	$ 362,817,755.69	$ 362,466,109.46	$ 367,292,626.28
$ 318,484,041.47	$ 319,854,847.96	$ 324,035,957.08	$ 329,394,101.13	$ 337,288,077.41	$ 341,931,592.87	$ 349,022,403.76	$ 352,998,711.08	$ 355,358,930.84

Table 45. Galway LNG NPV 0.525 MTPA after Galway 2013 (1 of 3)

		2015	2016	2017	2018	2019	2020	2021
Volume	(mmBtu)	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01
US GoM LNG Supply	**Total Delivered Cost to HI**	**$354,287,438.99**	**$ 372,389,716.89**	**$ 377,561,796.29**	**$387,905,955.10**	**$393,078,034.50**	**$ 400,836,153.60**	**$ 406,008,233.00**
Jorda Cove LNG Supply	**Total Delivered Cost to HI**	**$ 328,427,041.98**	**$ 343,943,280.19**	**$ 351,701,399.29**	**$362,045,558.09**	**$367,217,637.49**	**$ 372,389,716.89**	**$ 380,147,836.00**
Canada LNG Supply	**Total Delivered Cost to HI. High Forecast**	**$ 545,654,376.84**	**$ 555,998,535.64**	**$ 571,514,773.84**	**$589,617,051.75**	**$594,789,131.15**	**$ 623,235,567.86**	**$ 641,337,845.76**
LSFO		$ 571,514,773.84	$ 568,928,734.14	$ 592,203,091.45	$607,719,329.65	$625,821,607.56	$ 623,235,567.86	$ 641,337,845.76
ULSD		$ 721,505,076.48	$ 721,505,076.48	$ 747,365,473.49	$768,053,791.09	$788,742,108.70	$ 812,016,466.00	$ 832,704,783.61

Cash Flow GoM	$ 367,217,637.49	$ 349,115,359.59	$ 369,803,677.19	$380,147,836.00	$395,664,074.20	$ 411,180,312.40	$ 426,696,550.61
Cash Flow Jordan Cove	$ 393,078,034.50	$ 377,561,796.29	$ 395,664,074.20	$406,008,233.00	$421,524,471.21	$ 439,626,749.11	$ 452,556,947.61
Cash Flow Canada	$ 175,850,699.64	$ 165,506,540.84	$ 175,850,699.64	$178,436,739.34	$193,952,977.55	$ 188,780,898.15	$ 191,366,937.85

Cash Flow GoM	ULSD Comparison	Discounted	0.02	$ 418,329,951.58
Cash Flow Jordan Cove	ULSD Comparison	Discounted	0.02	$ 443,683,281.97
Cash Flow Canada	ULSD Comparison	Discounted	0.02	$ 187,614,644.95

Cost GoM	ULSD Comparison		Discounted	0.02	$ 398,047,287.26
Cost Flow Jordan Cove	ULSD Comparison		Discounted	0.02	$ 372,693,956.86
Cost Flow Canada	ULSD Comparison		Discounted	0.02	$ 628,762,593.88

Duration	Source	NPV
20 yr	**NPV GoM**	$ 6,100,776,492.75
20 yr	**NPV Jordan Cove**	$ 6,662,768,020.24
20 yr	**NPV Canada**	$ 1,828,130,401.92
10 yr	**NPV GoM**	$ 4,236,917,688.26
10 yr	**NPV Jordan Cove**	$ 4,451,462,582.14
10 yr	**NPV Canada**	$ 1,755,427,894.84

Table 46. Galway LNG NPV 0.525 MTPA after Galway 2013 (2 of 3)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	25860397.01	13545922.24	13545922.24
$418,938,431.51	**$429,282,590.31**	**$437,040,709.41**	**$444,798,828.51**	**$455,142,987.31**	**$462,901,106.42**	**$ 470,659,225.52**	**$ 478,417,344.62**	**$256,017,930.36**	**$331,875,094.92**
$393,078,034.50	**$403,422,193.30**	**$411,180,312.40**	**$418,938,431.51**	**$429,282,590.31**	**$437,040,709.41**	**$ 447,384,868.21**	**$ 457,729,027.02**	**$243,826,600.35**	**$284,464,367.07**
$662,026,163.37	**$682,714,480.97**	**$705,988,838.28**	**$729,263,195.58**	**$752,537,552.89**	**$775,811,910.20**	**$ 801,672,307.20**	**$ 830,118,743.91**	**$449,724,618.42**	**$535,063,928.54**
$662,026,163.37	$682,714,480.97	$705,988,838.28	$729,263,195.58	$752,537,552.89	$775,811,910.20	$ 801,672,307.20	$ 830,118,743.91	$449,724,618.42	$535,063,928.54
$855,979,140.92	$881,839,537.92	$907,699,934.93	$933,560,331.93	$962,006,768.64	$987,867,165.65	$ 1,016,313,602.36	$ 1,042,173,999.36	$560,801,180.80	$577,056,287.49
$437,040,709.41	$452,556,947.61	$470,659,225.52	$488,761,503.42	$506,863,781.33	$524,966,059.23	$ 545,654,376.84	$ 563,756,654.74	$304,783,250.43	$245,181,192.57
$462,901,106.42	$478,417,344.62	$496,519,622.52	$514,621,900.43	$532,724,178.33	$550,826,456.24	$ 568,928,734.14	$ 584,444,972.35	$316,974,580.45	$292,591,920.42
$193,952,977.55	$199,125,056.95	$201,711,096.65	$204,297,136.35	$209,469,215.75	$212,055,255.45	$ 214,641,295.15	$ 212,055,255.45	$111,076,562.38	$ 41,992,358.95
$420,069,886.01	$426,454,519.39	$434,816,372.71	$442,686,352.31	$450,080,532.49	$457,014,546.29	$ 465,710,756.63	$ 471,726,349.53	$250,028,421.32	$197,190,171.07
$444,926,092.29	$450,823,349.07	$458,707,382.20	$466,108,910.63	$473,043,824.96	$479,527,578.13	$ 485,575,196.48	$ 489,037,408.22	$260,029,558.18	$235,320,867.13
$186,421,547.05	$187,639,988.53	$186,349,874.02	$185,038,210.75	$186,002,669.04	$184,606,861.06	$ 183,194,278.67	$ 177,438,351.66	$ 91,121,469.10	$ 33,772,902.23
$402,670,541.62	$404,522,572.68	$403,758,060.38	$402,868,003.16	$404,153,947.54	$402,983,269.88	$ 401,703,117.09	$ 400,318,232.40	$210,023,873.91	$266,914,872.44
$377,814,335.35	$380,153,743.00	$379,867,050.89	$379,445,444.84	$381,190,655.06	$380,470,238.05	$ 381,838,677.24	$ 383,007,173.70	$200,022,737.06	$228,784,176.37
$636,318,880.59	$643,337,103.54	$652,224,559.07	$660,516,144.71	$668,231,810.99	$675,390,955.11	$ 684,219,595.05	$ 694,606,230.27	$368,930,826.13	$430,332,141.28

Table 47. Galway LNG NPV 0.525 MTPA after Galway 2013 (3 of 3)

2032	2033	2034	2035	2036	2037	2038	2039	2040
13545922.24	13545922.24	13545922.24	13545922.24	13545922.24	13545922.24	13545922.24	13545922.24	13545922.24
$ 337,293,463.81	**$344,066,424.93**	**$353,548,570.50**	**$364,385,308.30**	**$376,576,638.31**	**$388,767,968.33**	**$402,313,890.57**	**$411,796,036.14**	**$422,632,773.93**
$ 289,882,735.97	**$296,655,697.09**	**$306,137,842.66**	**$316,974,580.45**	**$329,165,910.47**	**$342,711,832.71**	**$356,257,754.95**	**$364,385,308.30**	**$375,222,046.09**
$ 551,319,035.23	**$568,928,734.14**	**$586,538,433.06**	**$605,502,724.20**	**$624,467,015.33**	**$644,785,898.70**	**$665,104,782.06**	**$686,778,257.64**	**$709,806,325.45**
$ 551,319,035.23	$ 568,928,734.14	$ 586,538,433.06	$ 605,502,724.20	$ 624,467,015.33	$ 644,785,898.70	$ 665,104,782.06	$ 686,778,257.64	$ 709,806,325.45
$ 593,311,394.18	$ 608,211,908.64	$ 625,821,607.56	$ 642,076,714.25	$ 642,076,714.25	$ 642,076,714.25	$ 642,076,714.25	$ 642,076,714.25	$ 642,076,714.25
$ 256,017,930.36	$ 264,145,483.71	$ 272,273,037.05	$ 277,691,405.95	$ 265,500,075.93	$ 253,308,745.92	$ 239,762,823.67	$ 230,280,678.11	$ 219,443,940.31
$ 303,428,658.21	$ 311,556,211.55	$ 319,683,764.90	$ 325,102,133.80	$ 312,910,803.78	$ 299,364,881.54	$ 285,818,959.30	$ 277,691,405.95	$ 266,854,668.16
$ 41,992,358.95	$ 39,283,174.50	$ 39,283,174.50	$ 36,573,990.05	$ 17,609,698.91	$ (2,709,184.45)	$ (23,028,067.81)	$ (44,701,543.40)	$ (67,729,611.21)
$ 201,868,390.92	$ 204,193,050.26	$ 206,348,934.65	$ 206,328,805.01	$ 193,402,418.85	$ 180,903,623.08	$ 167,872,188.76	$ 158,071,740.83	$ 147,679,481.05
$ 239,251,426.27	$ 240,843,084.92	$ 242,280,341.18	$ 241,555,674.16	$ 227,938,565.08	$ 213,795,190.91	$ 200,118,823.89	$ 190,615,922.77	$ 179,585,541.78
$ 33,110,688.46	$ 30,367,171.58	$ 29,771,736.84	$ 27,175,013.34	$ 12,827,711.45	$ (1,934,798.11)	$ (16,123,317.56)	$ (30,684,514.40)	$ (45,580,086.75)
$ 265,953,594.39	$ 265,974,537.26	$ 267,945,631.56	$ 270,743,651.46	$ 274,315,675.72	$ 277,643,528.47	$ 281,683,842.16	$ 282,669,465.96	$ 284,419,741.29
$ 228,570,559.03	$ 229,324,502.60	$ 232,014,225.03	$ 235,516,782.31	$ 239,779,529.50	$ 244,751,960.64	$ 249,437,207.03	$ 250,125,284.02	$ 252,513,680.57
$ 434,711,296.85	$ 439,800,415.95	$ 444,522,829.38	$ 449,897,443.13	$ 454,890,383.12	$ 460,481,949.65	$ 465,679,348.49	$ 471,425,721.19	$ 477,679,309.09

Table 48. LNG Port Comparison (after Galway, 2013)

			Total Price for various Annual Volumes (MTPA*) and Supplier locations					
	Terminal Configuration	Supplier	0.85	0.65	0.53	0.55	0.40	0.28
$ 195	Onshore LNG Terminal	Kitimat	$196,785,306.78	$228,926,085.92	$154,812,650.98	$259,268,951.75	$141,468,686.13	$187,574,079.65
		US Gom	$242,841,442.41	$202,031,273.03	$143,064,642.06	$161,196,474.70	$116,248,641.80	$ 92,545,740.77
		Jordan Cove	$202,646,996.77	$163,289,935.41	$139,931,839.68	$143,586,775.79	$114,081,294.24	$ 90,890,675.36
		E. Australia	$208,508,686.76	$159,447,819.29	$130,011,298.80	$134,917,385.55	$ 98,121,734.95	$ 68,685,214.46
$ 149	Small Scale Onshore	Kitimat	$180,037,621.10	$162,009,230.04	$121,918,225.99	$190,455,666.75	$117,627,862.98	$120,681,852.72
		Jordan Cove	$173,757,238.97	$158,167,113.91	$114,347,286.90	$205,356,181.22	$117,036,768.19	$115,578,734.38
$ 147	2 x FSRU - Double Buoy	Kitimat	$141,936,636.17	$162,969,759.07	$127,400,630.15	$179,348,010.51	$122,750,684.48	$150,197,185.84
		US Gom	$205,996,533.91	$174,816,283.80	$130,272,365.67	$182,599,031.85	$124,918,032.04	$151,714,329.13
		Jordan Cove	$185,480,618.94	$164,250,464.45	$128,705,964.48	$180,973,521.18	$123,538,810.87	$150,886,796.43
		E. Australia	$138,587,099.03	$160,408,348.32	$125,312,095.23	$177,722,499.84	$121,174,431.71	$149,093,808.90
$ 139	2 x FSRU - Single Buoy	Kitimat	$133,562,793.33	$153,364,468.75	$120,873,958.53	$168,782,191.16	$116,642,705.00	$141,921,858.80
		US Gom	$197,622,691.06	$165,210,993.48	$123,745,694.04	$172,033,212.50	$118,810,052.55	$143,439,002.09
		Jordan Cove	$135,237,561.89	$154,645,174.13	$122,179,292.85	$170,407,701.83	$117,430,831.38	$142,611,469.38
		E. Australia	$130,213,256.19	$150,803,058.00	$118,785,423.60	$167,156,680.49	$115,066,452.23	$140,818,481.86
$ 100	Dockside Fullsize FSRU	Kitimat	$107,185,188.37	$118,145,070.92	$ 81,713,928.77	$130,311,771.99	$ 73,098,722.22	$ 92,131,974.42
		US Gom	$153,241,324.00	$169,693,462.29	$102,077,144.24	$164,176,577.60	$ 96,742,513.77	$119,854,320.01
		Jordan Cove	$113,046,878.36	$130,952,124.67	$ 98,944,341.86	$146,566,878.68	$ 94,575,166.21	$ 76,822,619.39
		E. Australia	$118,908,568.35	$127,110,008.55	$ 89,023,800.99	$137,897,488.44	$ 78,615,606.91	$ 95,993,793.71
$ 129	Dockside Small/Mid FSRU	Kitimat	$157,846,937.57	$136,074,946.18	$103,904,612.30	$160,112,800.92	$120,583,336.92	$ 98,338,469.70
		Jordan Cove	$151,566,555.44	$132,232,830.05	$ 96,333,673.21	$175,013,315.39	$119,992,242.13	$ 93,235,351.36
$ 165	ATB Regas Barges	Kitimat	$180,037,621.10	$202,351,449.38	$125,573,162.10	$215,651,082.12	$129,252,727.16	$139,715,104.92
		Jordan Cove	$184,643,234.66	$171,614,520.36	$127,661,697.02	$212,129,142.34	$134,375,548.66	$126,612,503.77
			$ -	$ 40,342,219.34	$ 3,654,936.11	$ 25,195,415.37	$ 11,624,864.18	$ 19,033,252.20

Per ton of LNG		0.85 mtpa $/ton	0.65 mpta $/ton	0.53 mtpa $/ton	0.55 mtpa $/ton	0.4 mtpa $/ton	0.28 mtpa $/ton
Dockside Fullsize FSRU (Pearl Harbor option)	$ 201.79	$ 126.10	$ 181.76	$ 154.18	$ 236.93	$ 182.75	$ 329.04
Dockside Small/Mid FSRU	$ 255.81	$ 185.70	$ 209.35	$ 196.05	$ 291.11	$ 301.46	$ 351.21
Small Scale Onshore	$ 293.74	$ 211.81	$ 249.24	$ 230.03	$ 346.28	$ 294.07	$ 431.01
Rule of thumb	$ 44.23	$ 59.60	$ 27.58	$ 41.87	$ 54.18	$ 60.00 plug	$ 22.17

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